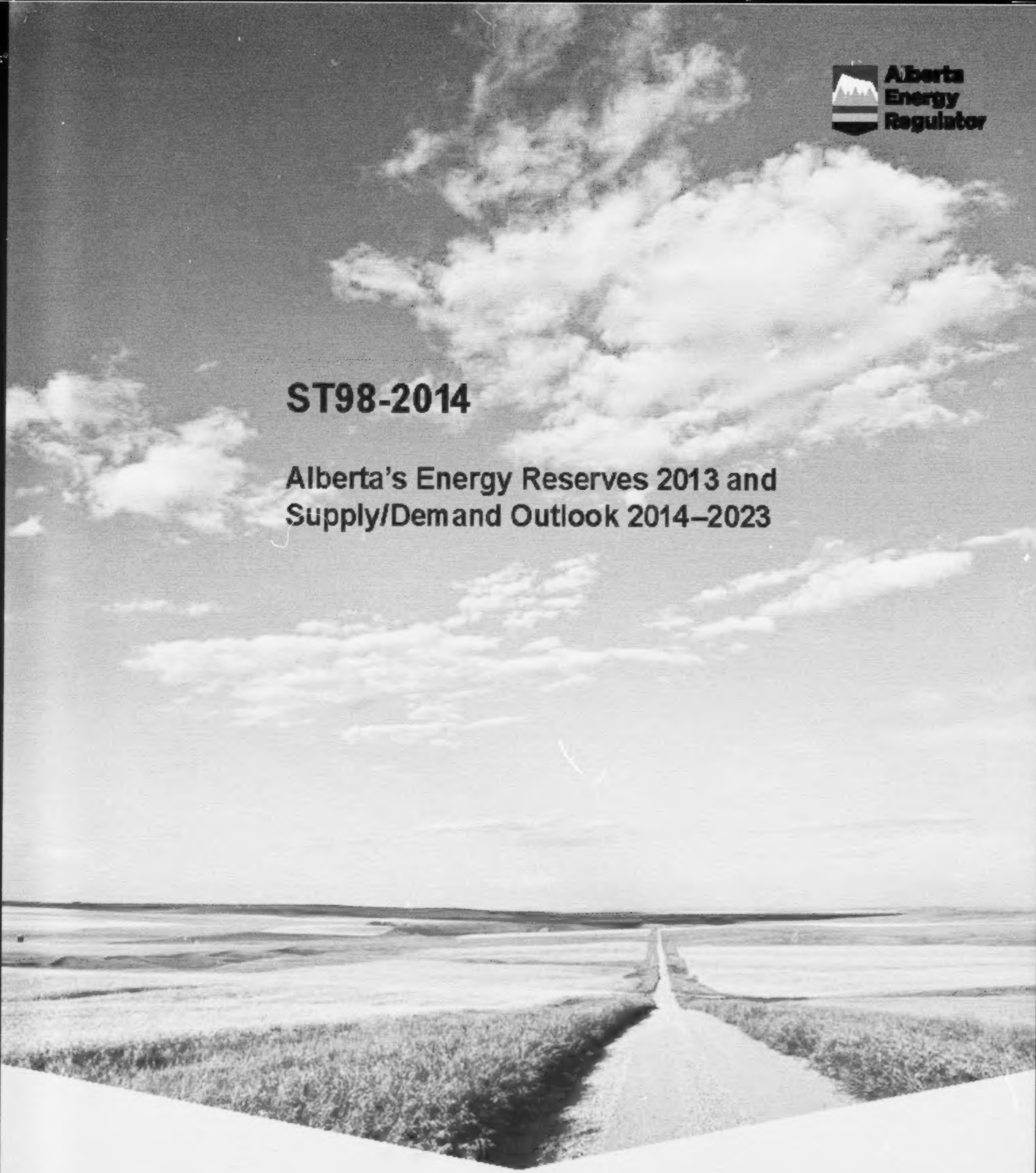

Alberta Energy Regulator

ST98-2014

Alberta's Energy Reserves 2013 and Supply/Demand Outlook 2014–2023

ST98-

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The following related documents are also available from the AER Order Fulfillment Team (telephone: 403-297-8311; when connected, press 2):

- CD with detailed data tables for crude oil and natural gas, as well as map of Designated Fields, Oil Sands Areas, and Development Entities, $546
- CD with Field and Pool Code Conversion File, $459
- CD with Gas Pool Reserve File (ASCII format), $3095
- CD with Oil Pool Reserves File (ASCII format), $1834
- Map-90: Map of Designated Fields, Oil Sands Areas, and Development Entities: 60 x 101 cm, $63; 33 x 54 cm, $29

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OVERVIEW

The Alberta Energy Regulator (AER) was established in June 2013 with the proclamation of the *Responsible Energy Development Act* (*REDA*). The AER has assumed the functions previously carried out by the Energy Resources Conservation Board (ERCB) and has acquired additional responsibilities in the areas of public lands, water, and the environment.

The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources over their entire life cycle. This includes allocating and conserving water resources, managing public lands, and protecting the environment while providing economic benefits for all Albertans.

Like the former ERCB, the AER appraises the province's energy resources and its productive capacity and establishes requirements for energy resources and energy in Alberta. This is done to satisfy, in part, the AER's legislated requirement to provide information regarding the energy resources of Alberta.

Providing information to support good decision-making is a key service of the AER. Making energy resource data available to everyone involved—landowners, communities, industry, government, and interested groups—results in better decisions that affect the development of Alberta's resources.

Every year the AER issues a report providing stakeholders with independent and comprehensive information on the state of reserves, supply, and demand for Alberta's diverse energy resources: crude bitumen, crude oil, natural gas, natural gas liquids, sulphur, and coal. This year's report includes estimates of initial established reserves (recoverable quantities estimated to be in the ground before any production), remaining established reserves (recoverable quantities known to be left), and ultimate potential (recoverable quantities that have already been discovered plus those that have yet to be discovered). It also includes a 10-year supply and demand forecast for Alberta's energy resources from 2014 to 2023 (the forecast period); additionally, this report provides some historical trends on energy commodities so that supply and price relationships may be better understood.

HIGHLIGHTS

Over the last decade, production of bitumen has more than doubled while production of other energy commodities has marginally increased or declined.

Alberta's natural gas is losing market share to U.S. shale gas in the eastern United States and central Canada.

About 80 per cent of crude oil wells and 55 per cent of natural gas wells placed on production in 2013 were horizontal wells.

Summary of Energy Reserves, Production, and Demand in Alberta

In 2013, Alberta produced 11 821 petajoules (10^{15} joules) of energy from all sources, including renewable sources. This is equivalent to more than 5.3 million barrels per day of conventional light-medium crude oil. In 2023, Alberta is projected to

produce 15 945 petajoules of energy from all sources, which is equivalent to over 7.1 million barrels per day of conventional light- and medium-quality crude oil. A breakdown of production by energy source is illustrated in **Figure 1**.

Reserves

Reserves are the recoverable quantities of energy resource commodities that are known with reasonable certainty. In-place resources are the larger quantities existing in the ground from which a portion has been, or may be, recovered as reserves. The AER also estimates a quantity (the ultimate potential) from discovered and undiscovered in-place resources that may be ultimately recovered when all future resource extraction activities have ceased within Alberta. The AER's current reserves and resource classification system is discussed in **Section 2.4**.

Table 1 summarizes Alberta's energy reserves, resources, and production at the end of 2013.

In 2012, the Alberta Geological Survey released the study *ERCB/AGS Open File Report 2012-06: Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential* that contained estimates of the ultimate natural gas, natural gas liquids, and crude oil resources in-place in six key geological formations where shale is the predominate rock type. In 2013, the National Energy Board, with information from several provincial government authorities (including the AER), released a study that considered the hydrocarbon ultimate potential of the Montney Formation, one of the six formations studied by the AER. Since the results of this study are only a partial estimate of shale hydrocarbons in Alberta, they have not been included in **Table 1**. The summary of both study results is given in **Section 2.2.2** and **Section 2.3.3**, respectively.

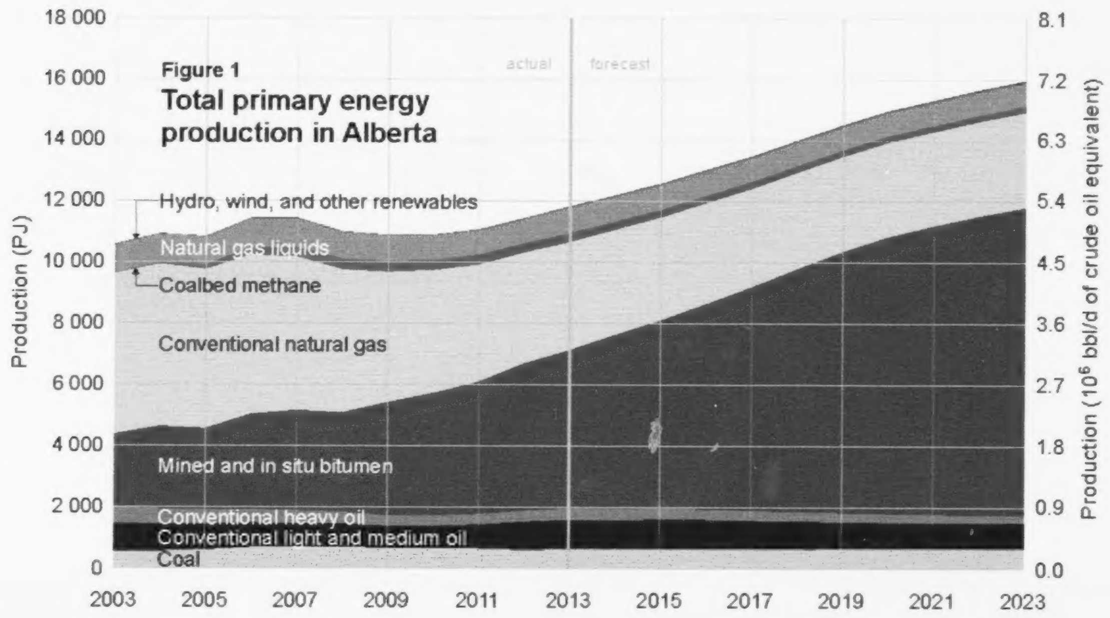


Table 1 Reserves, resources, and production summary, 2013

	Crude bitumen		Crude oil		Natural gas[a]		Raw coal	
	(million cubic metres)	(billion barrels)	(million cubic metres)	(billion barrels)	(billion cubic metres)	(trillion cubic feet)	(billion tonnes)	(billion tons)
Initial in-place resources	293 125	1 845	12 510	78.7	9 699	344	94	103
Initial established reserves	28 092	177	2 970	18.7	5 522	196	35	38
Cumulative production	1 527	9.6	2 687	16.9	4 573	162	1.56	1.72
Remaining established reserves	**26 565**	**167**	**283**	**1.8**	**949**[b]	**33.7**[b]	**33**	**37**
Annual production	121	0.761	33.8	0.213	102.0	3.6	0.029[c]	0.032[c]
Ultimate potential (recoverable)	50 000	315	3 130	19.7	6 276[d]	223[d]	620	683

[a] Expressed as "as is" gas, except for annual production, which is 37.4 megajoules per cubic metre; includes coalbed methane.

[b] Measured at field gate.

[c] Annual production is marketable.

[d] Does not include unconventional natural gas.

Production

Raw bitumen in Alberta is produced either by mining the oil sands or by using various in situ techniques and wells to produce bitumen. Bitumen production accounted for 80 per cent of Alberta's total crude oil and bitumen production in 2013. Bitumen production increased by 5 per cent at mining projects and by 12 per cent at in situ projects in 2013, resulting in an overall raw bitumen production increase of 8 per cent relative to 2012.

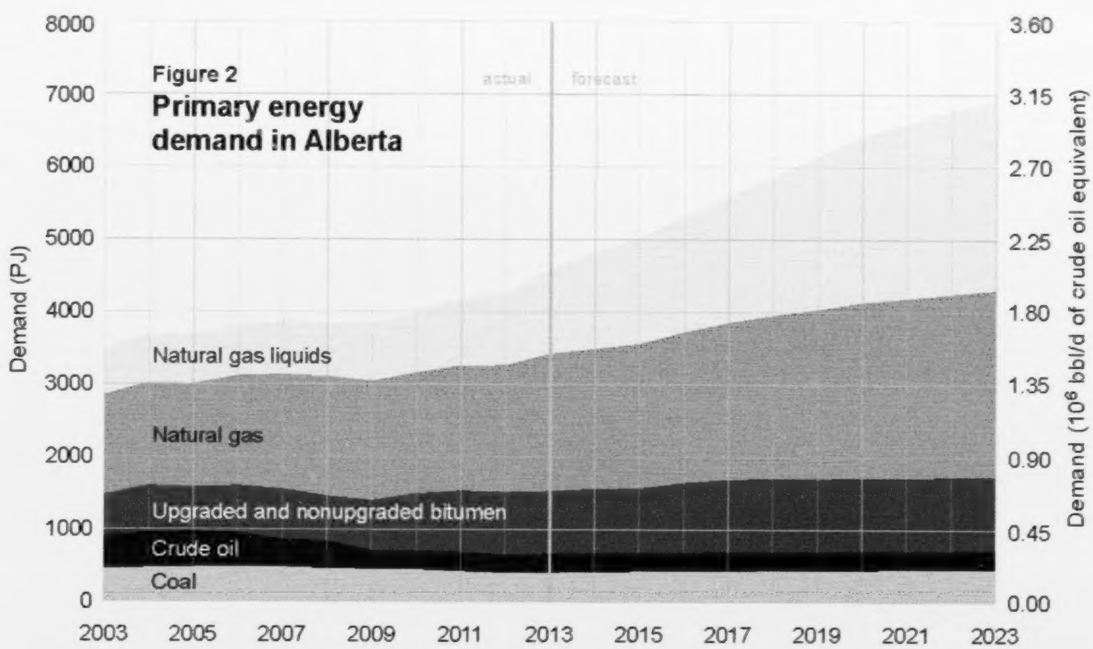
In 2013, crude oil production increased by about 5 per cent, total marketable natural gas production in Alberta declined by 3 per cent, total natural gas liquids[1] (NGLs) production increased by 6 per cent, sulphur production increased by 2 per cent, and total coal production increased by 3 per cent.

While this report focuses on the fossil-based energy resources in the province, a relatively small amount of energy, about 0.2 per cent, is also produced from renewable energy sources, such as hydro and wind power.

Energy Demand

Alberta's primary energy demand by energy type is shown in **Figure 2**. In 2013, demand for all fossil-based energy commodities increased by 8 per cent relative to 2012. Demand for natural gas and pentanes plus is projected to increase throughout the forecast period in conjunction with the expected increase in crude bitumen production. Total primary energy consumption in 2013 was 4575 petajoules, equivalent to about 2 million barrels per day of crude oil. This amount is projected to increase to 6915 petajoules, or 3.1 million barrels per day, by 2023.

[1] Natural gas liquids refers to ethane, propane, butanes, and pentanes plus obtained from the processing of raw gas or condensate. See discussion in **Section 6**.



The primary energy removals from Alberta are shown in **Figure 3**. Most shipments are to the United States. Natural gas removals from Alberta are projected to decrease over the forecast period as Alberta loses market share to the U.S. shale gas in the eastern United States and central Canada. Total primary energy removals from the province are expected to reach 10 332 petajoules in 2023, equivalent to 4.6 million barrels per day of crude oil, up from 7373 petajoules, or 3.3 million barrels per day, in 2013.

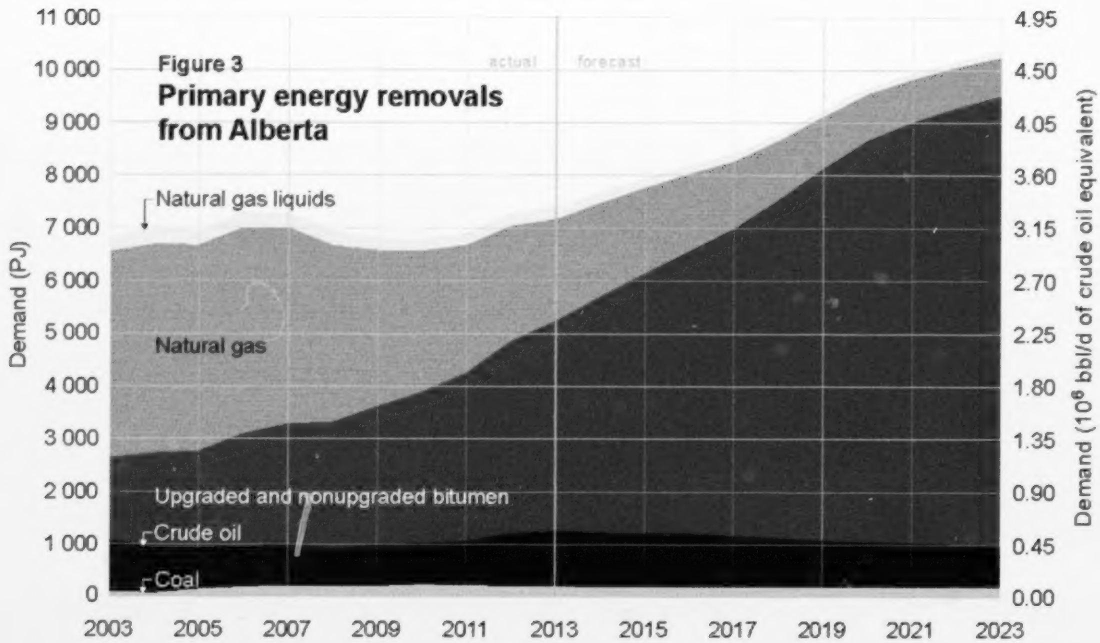
Alberta Hydrocarbon Production within the Canadian Context

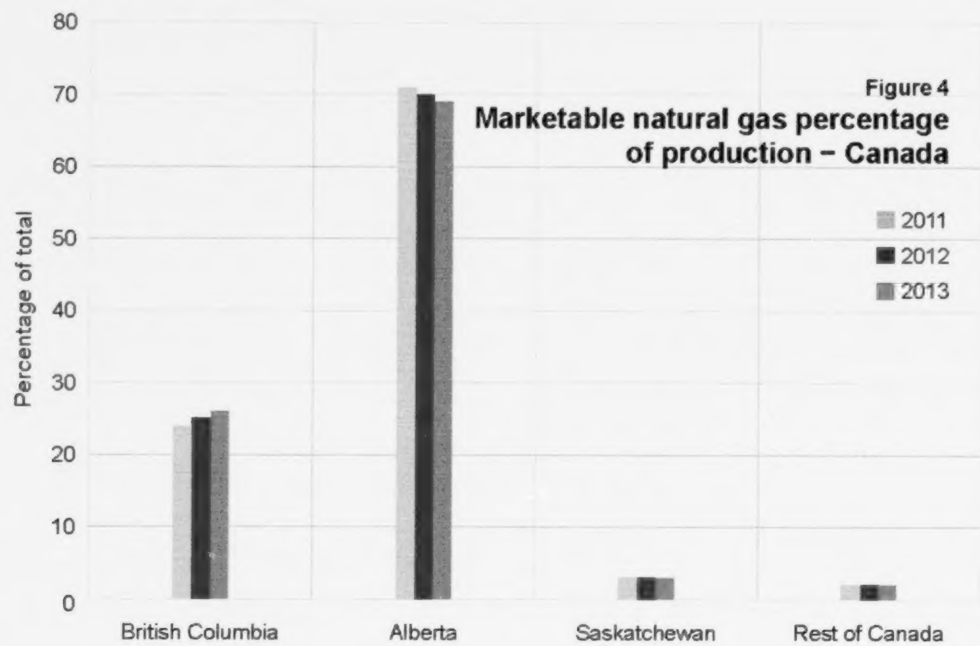
Alberta is Canada's largest producer of marketable natural gas. In 2013, Alberta produced 69 per cent of Canada's total production, down from 70 per cent in 2012. Over the same period, Canada's second largest contributor, British Columbia, increased its share from 25 per cent to 26 per cent. **Figure 4** shows the percentage contributed by region in Canada for 2011, 2012, and 2013.

Alberta is also the largest contributor to Canadian oil and equivalent[2] production and is the only contributor of upgraded and nonupgraded bitumen, which are the marketed components of raw bitumen production. **Figure 5** illustrates the contribution percentage breakdown by category and region in Canada for 2013.

Only two provinces, Alberta and Saskatchewan, contribute to conventional heavy crude oil production in Canada. In 2013, Alberta accounted for 76 per cent of Canada's oil and equivalent production, with marketed bitumen representing 56 per cent of the total.

[2] Oil and equivalent includes light-medium and heavy crude oil, condensate (pentanes plus), and upgraded and nonupgraded bitumen.





Source: National Energy Board.

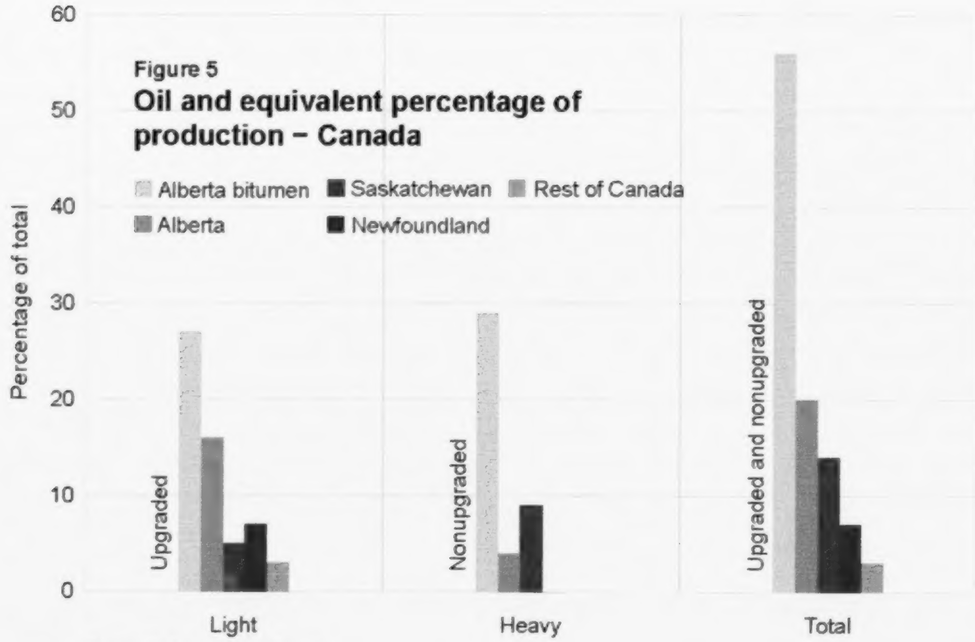


Figure 5
Oil and equivalent percentage of production – Canada

Source: National Energy Board.

Oil and Gas Prices and Alberta's Economy

Crude Oil Prices – 2013

Crude oil prices strengthened at the beginning of the year in response to the economic recovery in most countries after the 2008 recession. Additional demand for oil from emerging markets, along with continued tension in the Middle East, kept prices elevated. Prices, however, began to fall in March and reached yearly lows in May due to reports of high global crude oil stocks. Prices began to recover in June due to high seasonal demand and supply disruptions in Libya, Iran, Nigeria, Iraq, and some non-OPEC (Organization of Petroleum Exporting Countries) producers. By the fourth quarter of 2013, prices began to fall again due to higher supplies and fewer threats from the Middle East. Significant production outages in 2013 were offset by rising production in the United States and Saudi Arabia and as a result global crude oil prices were relatively stable.

The price for Brent Blend (Brent)[3] started the year at a relatively high level, it then fell during the year and averaged the year at a price lower than 2012. Brent averaged $108.56/barrel (bbl) in 2013, down 3 per cent from 2012. The price for West Texas Intermediate (WTI) light sweet crude oil averaged $98.05/bbl in 2013, up 4 per cent from 2012 and the highest annual average since 2008.[4]

[3] Brent Blend is a blend of light sweet crude oil from 15 different oil fields in the North Sea. Brent Blend futures are traded on the IntercontinentalExchange, Inc. and are considered a global benchmark for oil prices.

[4] In this report Brent spot prices and WTI near-month futures prices have been used.

In 2013, the price differential between Brent and WTI ranged from US$3.23/bbl to US$20.73/bbl and averaged US$10.51/bbl. This discount reflects the significant increases in U.S. supplies and the lack of pipeline capacity to move crude oil from Cushing, Oklahoma, to the U.S. Gulf Coast. New pipeline and railroad infrastructure partially alleviated the transportation constraints at Cushing, enabled crude oil to better reach refineries, and narrowed the differential.

Heavier Canadian crudes, such as Western Canadian Select (WCS),[5] have shown deeper discounts compared with other world heavy crude oils. In 2013, WCS averaged US$73.01/bbl, trading at US$25.04/bbl under the price of WTI, while Mexican Maya crude oil traded at average US$1.19/bbl discount to WTI. Maya crude oil is close to WCS quality. While Mexican Maya enjoys a location discount due to proximity to heavy-oil-capable refineries in the Gulf Coast, heavy Canadian crudes have been discounted due to distance and transportation constraints. The deep discount on heavy Canadian crudes is not expected to be alleviated until demand for Canadian crudes is increased by the addition of heavy refinery capacity and the alleviation of pipeline constraints.

Crude Oil Prices – Forecast

The AER bases its forecast on the expectation that the price of crude oil in North America, as measured by the price for WTI, will continue to be relatively volatile. The AER projects WTI to average US$95.00/bbl in 2014, with a range from US$85.00/bbl to US$105.00/bbl. The price of WTI is expected to increase throughout the forecast period as increasing crude oil demand exerts upward pressure on supplies and price. In 2023, WTI prices are projected to be US$111.81/bbl.

Natural Gas Prices – 2013

While North American crude oil prices closely track international prices, natural gas prices in North America reflect domestic supply and demand, with little global gas market influence aside from the impact of liquefied natural gas (LNG) imports. Alberta natural gas prices are heavily influenced by the market price at Henry Hub (near Erath, Louisiana) in the United States. The most significant change over the past couple of years in the market has been the increase in U.S. natural gas supply from shale gas, which has become economic due to horizontal drilling and multistage fracturing technology. Natural gas producers in North America have been, and are expected to continue to be, challenged by a weak price environment.

The average price of Alberta natural gas at the plant gate (Alberta reference price) in 2013 was Cdn$2.83 per gigajoule (GJ), compared with Cdn$2.14/GJ in 2012—a 32 per cent increase. The monthly Alberta reference price for natural gas was highest in May at Cdn$3.24/GJ and lowest in September at Cdn$2.14/GJ. In 2013, U.S. natural gas prices at Henry Hub also increased by 32 per cent over 2012. Natural gas prices in 2013 were affected by below normal winter temperatures and stronger consumption by the U.S. industrial sector.

[5] Western Canadian Select is a type of marketed crude oil produced in western Canada and made up of heavy Canadian conventional crude oil and crude bitumen blended with diluent.

Natural Gas Prices – Forecast

The AER projects the Alberta natural gas reference price to average Cdn$3.84/GJ in 2014, with a range between Cdn$2.89/GJ and Cdn$4.79/GJ. In the near term, prices are projected to remain weak due to increasing gas supply in North America. Longer term, a combination of LNG exports and increased domestic demand is to contribute to a strengthening of natural gas prices. Over the forecast period, the price of natural gas is projected to increase slowly, reaching Cdn$5.90/GJ in 2023.

Alberta's Economy – 2013

Alberta real gross domestic product (GDP) growth has mostly outperformed Canadian real GDP growth over the past decade, particularly in the 2003–2006 timeframe and after the 2008 recession. Average Alberta GDP growth from 2003 to 2013 was 3.2 per cent, compared with a Canadian average of 1.9 per cent. Similarly, the unemployment rate in Alberta averaged 4.7 per cent over that period, while the Canadian unemployment rate averaged 7.1 per cent.

In 2013, the total value of Alberta's energy resource production increased by 13 per cent relative to 2012. In 2013, combined upgraded and nonupgraded bitumen revenues (value of production) were about 50 per cent greater than the combined revenues from conventional gas, conventional crude oil, natural gas liquids, and sulphur.

Alberta's Economy – Forecast

The AER expects global economic growth that began after the recession to continue or even gain increased momentum in the short and medium term. Increased manufacturing orders, improvement in construction, and high demand for transportation are drivers of the global growth. The economic growth will also be observed in Canada and Alberta. Alberta's economic growth is forecast to be 3.4 per cent in 2014, which is expected to outperform Canada's national growth rate. As a result, the AER projects a steady growth in the national and international demand for Alberta's energy in near term. Furthermore, growth in energy revenues are expected to be supported by a weaker Canadian dollar, which the AER projects as being 0.92 $US/$Cdn for 2014. Real GDP is expected to continue to grow at 3.0 per cent annually between 2015 to 2023.

The AER estimates that oil sands capital expenditures decreased to $24.4 billion in 2013, compared with $27.2 billion in 2012, the year of the last available data. Oil sands expenditures are predicted to decrease to $23.9 billion in 2014 and peak in 2016 at $30.8 billion. In 2013, some oil sands companies announced that they were cutting their capital budget spending and delaying the development of upcoming projects as a result of increased pressure from lower cost conventional oil development in Canada and the United States.

Crude oil and natural gas expenditures have rebounded significantly since the 2009 level of $12 billion and reached $26.1 billion in 2012 as activity in conventional basins shifted to the application of capital-intensive horizontal wells and multistage fracturing in tight oil and wet gas plays. Investment in oil and gas is expected to increase over the forecast period as producers continue to use the more costly technology and higher prices are expected.

Production from upgraded and nonupgraded bitumen derived from the oil sands is projected to more than offset the decline in conventional resource production, increasing from 62 per cent of total energy revenues in 2013 to 73 per cent of total energy revenues in 2023.

Continued investment in oil sands mining, upgrading, and in situ bitumen projects will continue to drive Alberta's production and export growth and the overall Alberta economy. Alberta's economic growth will continue to contribute strongly to Canadian economic growth.

Commodities

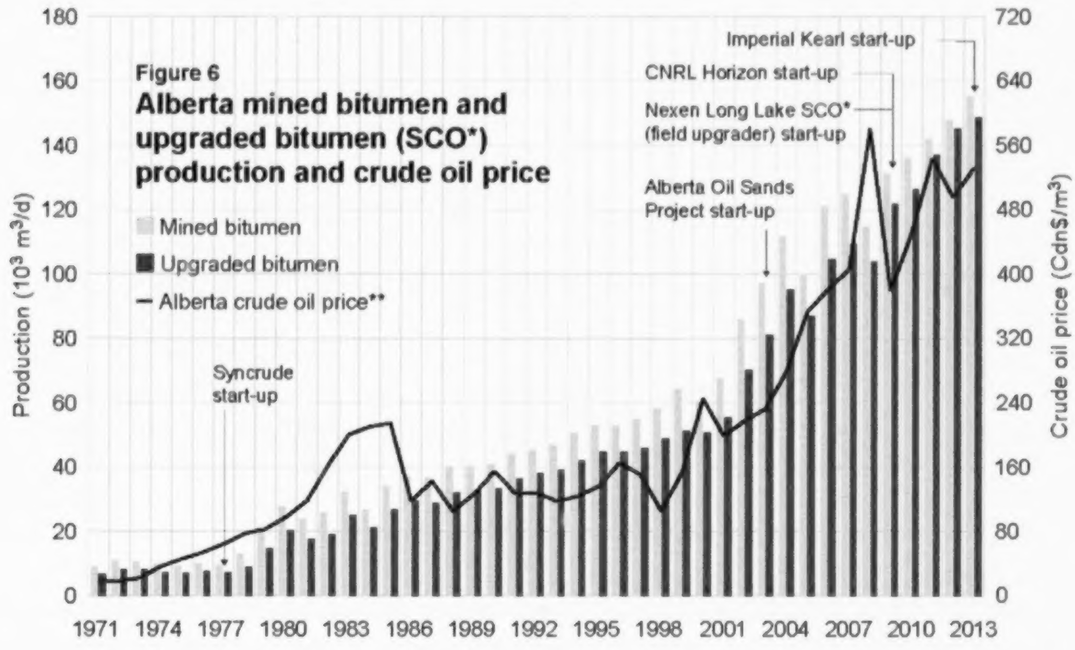
Crude Bitumen and Crude Oil

Crude Bitumen Reserves

The total remaining established reserves of in situ and mineable crude bitumen is 26.6 billion cubic metres (m^3) (167.2 billion barrels), slightly less than in 2012 due to 0.12 billion m^3 of production. Only 5.4 per cent of the initial established crude bitumen reserves have been produced since commercial production started in 1967.

Crude Bitumen Production

Figure 6 shows the historical mined bitumen and upgraded bitumen production between 1971 and 2013. Production began with the start-up of Great Canadian Oil Sands (Suncor) in 1967 and has been followed by other



* Synthetic crude oil.
** Source: Canadian Association of Petroleum Producers *Statistical Handbook*.

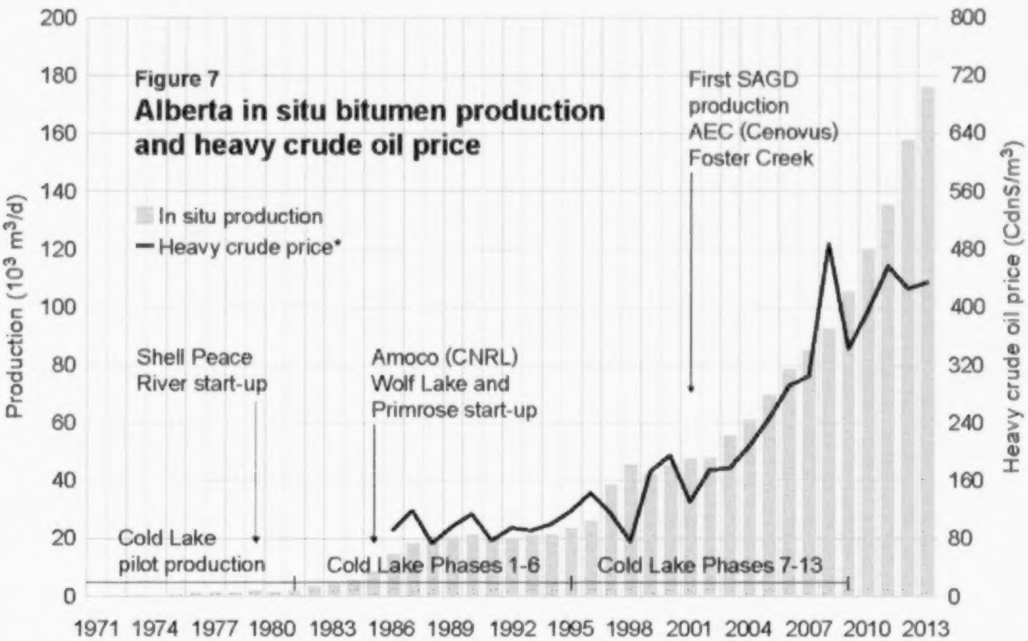
projects, the most recent being Imperial Oil Limited's Kearl project. The figure also shows the average Alberta wellhead price of crude oil.

Historical in situ bitumen production and the price of heavy crude oil are shown in **Figure 7**. Regionally, in situ production growth in 2013 was strongest in Athabasca (19 per cent increase), followed by Peace River (6 per cent increase), then Cold Lake (2 per cent increase).

In 2013, Alberta produced 56.6 million m^3 (357 million barrels) from mining and 64.3 million m^3 (405 million barrels) from in situ, totalling 121 million m^3 (761 million barrels). This is equivalent to 331.4 thousand m^3 (2.1 million barrels) per day. Total raw bitumen production is projected to reach 644 thousand m^3 (4.1 million barrels) per day by 2023.

Production from in situ projects exceeded mined production for the first time in 2012 and did so again in 2013. This percentage is expected to increase over the forecast period. In 2013, total in situ production accounted for 53 per cent of total bitumen production and is expected to reach 59 per cent in 2023.

The AER expects in situ crude bitumen production to increase to 379 thousand m^3 per day in 2023. The current forecast has increased over last year's primarily due to the addition of new proposed projects and accelerated development schedules for existing and approved projects. The AER projects that mined bitumen production will reach 265 thousand m^3 per day in 2023.



* Source: AER's *ST3: Alberta Energy Resource Industries Monthly Statistics.*

Upgraded Bitumen (SCO) Production

In 2013, all crude bitumen produced from mining, as well as a small portion of in situ production (about 12 per cent), was upgraded in Alberta, yielding 54.3 million m^3 (342 million barrels) of upgraded bitumen. In 2013, the percentage of raw crude bitumen sent to an upgrader was 52 per cent of total crude bitumen. Over the forecast period, this percentage is expected to decline to 36 per cent as a result of in situ production growth outpacing the growth in upgrading capacity. In 2023, upgraded bitumen production is forecast to increase to 76.2 million m^3 (479.3 million barrels).

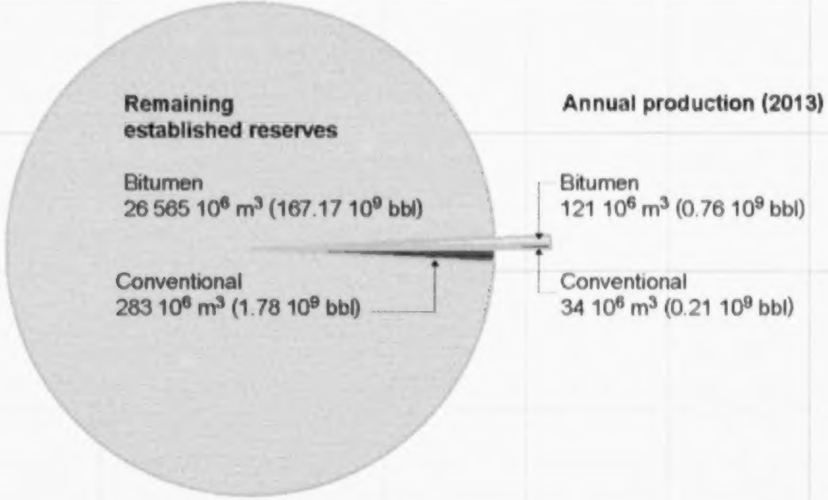
Over the next 10 years, mined bitumen is projected to continue to be the primary source of crude bitumen to be upgraded in Alberta. However, the percentage of in situ bitumen upgraded is expected to vary throughout the forecast period, before reaching about 7 per cent in 2023.

Crude Oil Reserves

The AER estimates the remaining established reserves of conventional crude oil in Alberta to be 283.4 million m^3 (1.8 billion barrels), representing about one third of Canada's remaining conventional reserves. This is a year-over-year increase from 2012 of 14.2 million m^3, or 5 per cent, resulting from all reserve adjustments less production in 2013.

Annual production and remaining established reserves for crude bitumen and crude oil are presented in **Figure 8**.

Figure 8
Alberta oil reserves

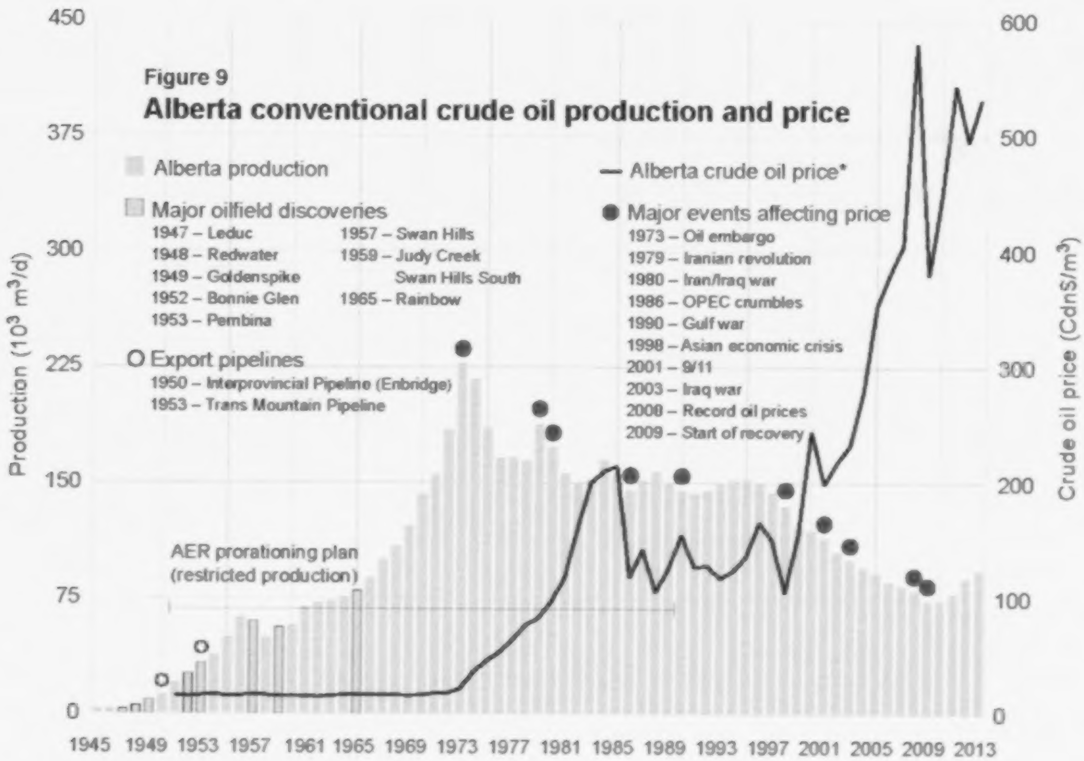


Crude Oil Production

Alberta's historical conventional crude oil production and the average Alberta wellhead price are shown in **Figure 9**. The first major oilfield discovered in Alberta was in Turner Valley in 1914. The Turner Valley oilfield became a major source of oil and gas production and for a time was the largest source in the British Empire. The discovery of Leduc Woodbend in 1947 jumpstarted Alberta crude oil production, which culminated in 1973 with peak production of 227.4 thousand m^3 per day. Major events that affected Alberta's crude oil production and crude oil prices are also noted in the figure.

In 2010, total crude oil production in Alberta reversed the downward trend that started in the early 1970s. Since 2010, light-medium crude oil production increased as a result of increased horizontal drilling activity and the introduction of multistage hydraulic fracturing technology. Alberta's production of conventional crude oil totalled 33.8 million m^3 (213 million barrels) in 2013, an increase of 5 per cent.

As forecast in previous reports, the AER believes that crude oil production peaked in 2013 and is expected to re-enter a period of slow decline.



* Source: CAPP *Statistical Handbook*.

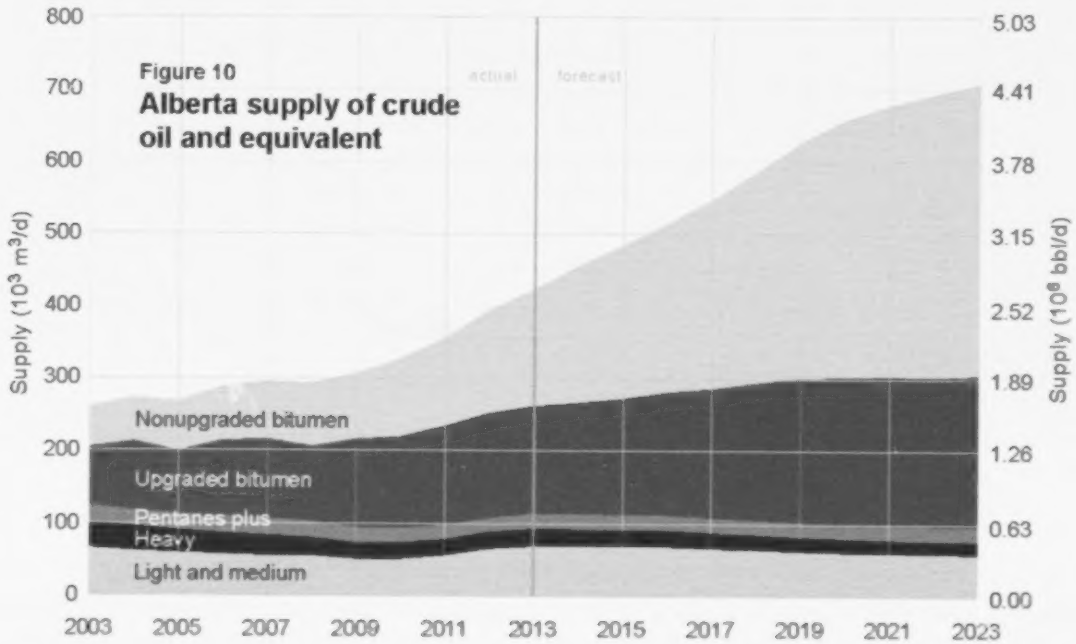
Total Oil Supply and Demand

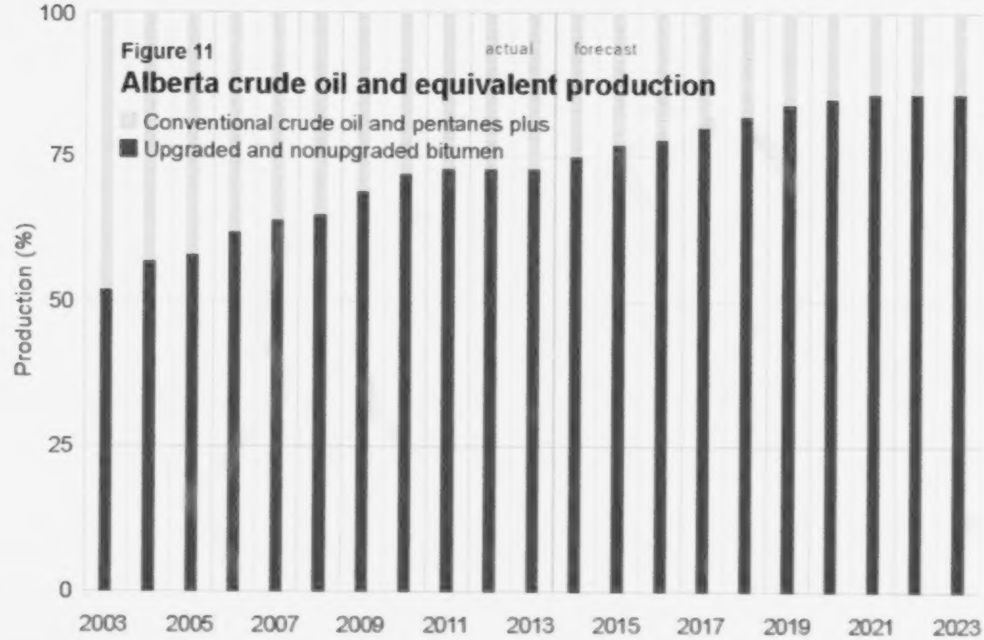
Figure 10 shows crude oil and equivalent supply. In 2013, Alberta's supply of crude oil and equivalent reached 423 thousand m^3 (2.7 million barrels) per day, a 7 per cent increase compared with 2012. Production is forecast to reach 708 thousand m^3 (4.4 million barrels) per day in 2023.

A comparison of conventional oil and bitumen production over the last 10 years, as illustrated in **Figure 11**, clearly shows the increasing contribution of bitumen to Alberta's oil production.

The AER estimates that bitumen production will roughly double by 2023. Over the forecast period, as illustrated in **Figure 11**, the growth in production of upgraded and nonupgraded bitumen is expected to more than offset the projected long-term decline in conventional crude oil. Upgraded and nonupgraded bitumen will account for 86 per cent of total production in 2023, compared with about 73 per cent in 2013.

Demand for oil produced in Alberta is from oil refineries, most of which are outside the province. Oil refineries use mainly crude oil, butanes, and natural gas as feedstock, along with upgraded and nonupgraded bitumen and pentanes plus, to produce a wide variety of refined petroleum products. Crude oil shipments outside of Alberta amounted to 81 per cent of total production in 2013. The AER expects that by 2023, this figure will slowly decrease to about 77 per cent of production due to the decline expected in Alberta light-medium and heavy crude oil production over the forecast period.





Natural Gas

Historical gas production and prices are shown in **Figure 12**. In the 1950s and 1960s, natural gas was mainly produced as a by-product of crude oil production and was flared as a waste product. During this period, natural gas prices were low. In the early 1970s, when OPEC increased crude oil prices, natural gas prices started to increase.

In 1980, through the National Energy Program, the federal government imposed regulated gas prices tied to crude oil prices based on their relative calorific values. High gas prices in the 1980s spurred drilling, which resulted in a significant oversupply of reserves.

In 1985, natural gas prices were deregulated in Canada. The removal of set prices, the oversupply of reserves, and the drop in demand because of a recession resulted in the decline of natural gas prices for the rest of the decade.

In the late 1980s and early 1990s, natural gas prices became more market responsive. Trading points were created at Henry Hub and at Alberta Energy Company's storage hub (AECO-C)[5] (near Suffield, Alberta) to facilitate natural gas being traded as a North American commodity.

More recently, shale gas production in the United States has significantly contributed to the growth in natural gas production, reversing the trend of annual U.S. production declines. Increased supply and lagging demand has resulted in low gas prices in North America and contributed to the reduction in natural gas activity in Alberta. The low gas prices, however, have prompted producers to consider building LNG facilities for export purposes.

[5] The AECO-C hub is a trading point that sets the main pricing index for Albertan and Canadian natural gas.

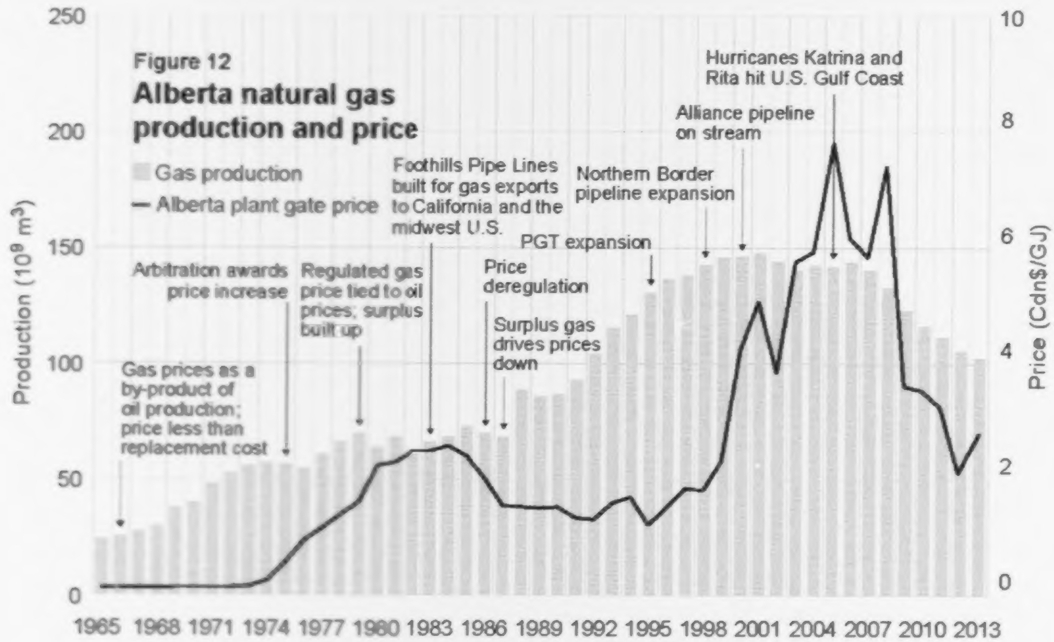
Natural gas is produced from conventional and unconventional reserves in Alberta, where unconventional gas is defined as coalbed methane (CBM) and shale gas. Marketable gas is the gas that remains after the raw gas is processed to remove constituents and that meets specifications for use as a fuel. Marketable gas reserves are determined by applying a surface loss or shrinkage factor to the raw gas volume. Most marketable natural gas in Alberta is produced from conventional sources.

Conventional Natural Gas Reserves

As of December 31, 2013, the AER estimates the remaining established reserves of marketable conventional gas in Alberta downstream of field plants to be 898 billion m^3, with a total energy content of about 35 exajoules. This decrease of 18.2 billion m^3 since December 31, 2012, is the result of all reserves additions less production during 2013. These reserves include 29.6 billion m^3 of ethane and other NGLs, which are present in marketable gas leaving the field plant and are subsequently recovered at straddle plants. Removal of NGLs results in a 4.6 per cent reduction in the average heating value, from 39.2 megajoules per m^3 to 37.4 megajoules per m^3, for gas downstream of straddle plants. Reserves added through drilling (new plus development) totalled 33.3 billion m^3, replacing 36 per cent of Alberta's 2012 production, one of the lowest replacement ratios in the last 15 years.

Unconventional Natural Gas Reserves

The AER estimates the initial established reserves of CBM to be 101.7 billion m^3 as of December 31, 2013, relatively unchanged from 2012. Remaining established reserves in 2013 are 51.5 billion m^3, down from 56.7 billion m^3 in 2012 due to production.



Total Natural Gas Production

Several major factors affect natural gas production, including natural gas prices, drilling and connection activity, accessibility of Alberta's remaining reserves, and performance characteristics of wells. In 2013, total marketable natural gas production in Alberta, including unconventional production, declined by 3 per cent to 280.2 million m^3 per day from 287.7 million m^3 per day. Total production from identified CBM and CBM hybrid connections decreased 6 per cent in 2013 to 20.9 million from the 2012 volume of 22.3 million m^3 per day. In 2013, natural gas from conventional gas and oil connections, at 258.7 million m^3 per day (standardized to 37.4 megajoules per m^3), represented 92 per cent of production. The remaining 8 per cent of gas supply came from CBM and minor shale gas connections at 20.9 million m^3 per day and 0.6 million m^3 per day, respectively.

Total Natural Gas Supply and Demand

The AER believes that new wells on production will not be able to sustain production levels over the forecast period.

Despite declining natural gas supply from conventional sources, sufficient supply exists to meet Alberta's demand. In 2013, about 50 per cent of Alberta production was consumed within Alberta compared with 44 per cent in 2012. The remainder was sent to other Canadian provinces and the United States. By the end of the forecast period, domestic demand in Alberta is forecast to represent about 78 per cent of total Alberta natural gas production, not including potential shale gas production or natural gas supply from British Columbia that connects to the pipeline network in Alberta.

Therefore, as Alberta requirements continue to increase and production continues to decline, less gas is forecast to be available for removal from the province. Alberta's historical and forecast marketable gas production (at 37.4 megajoules per m^3) and demand are shown in **Figure 13**.

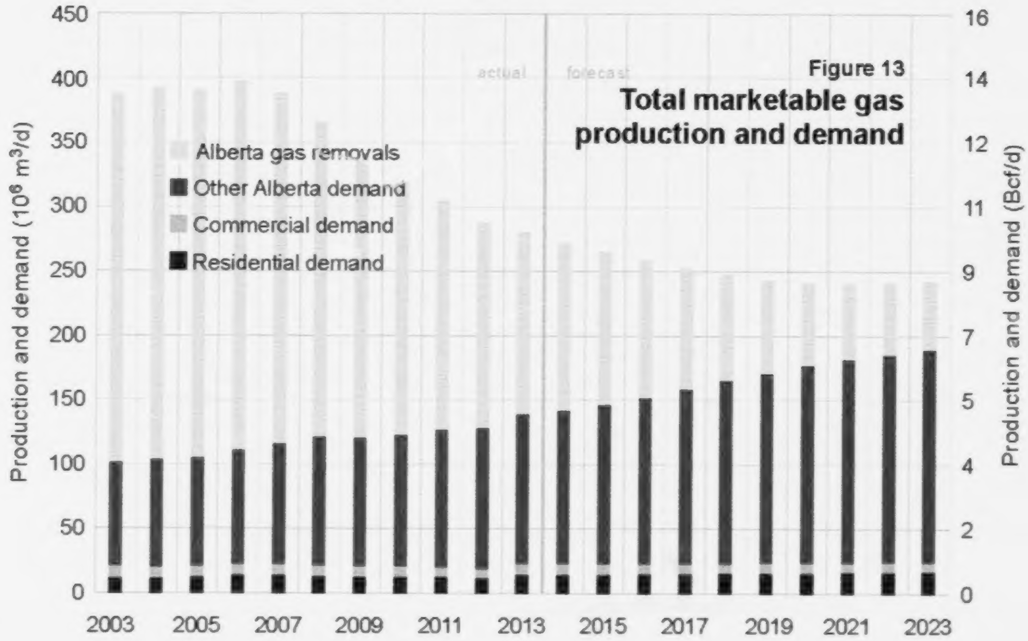
Ethane and Other Natural Gas Liquids

Ethane Reserves

As of December 31, 2013, the AER estimates remaining established reserves of extractable ethane to be 110.5 million m^3 in liquefied form. This estimate considers the recovery of liquid ethane from raw gas extracted at field and straddle plants in Alberta based on existing technology and market conditions.

Ethane Production

In 2013, ethane volumes extracted from conventional gas and oil sands off-gas at Alberta processing facilities increased to 36.7 thousand m^3 per day from 34.1 thousand m^3 per day in 2012. About 75 per cent of total ethane in the gas stream was extracted in 2013, while the remainder was left in the gas stream and sold for its heating value. This figure was 70 per cent in 2012. The AER expects that Alberta ethane supply will slightly increase over the next two years. New ethane supplies are expected to come from liquids-rich natural gas and oil sands off-gas. Ethane imports from the United States started in the first quarter of 2014 and are projected to continue to increase throughout the forecast period, reaching 7.9 thousand m^3 per day in 2023.



Propane, Butane, and Pentanes Plus Reserves

As of December 31, 2013, the AER estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 65.5 million m^3, 35.4 million m^3, and 44.9 million m^3, respectively. Cumulatively, these NGLs reserves equate to 67 per cent of Alberta's remaining light-medium crude oil reserves. This is a decrease from 101 per cent in 2000 due to the decline in NGLs reserves and the recovery of light-medium crude oil reserves over that period.

Propane, Butane, and Pentanes Plus Production

The production of propane increased for the second year in a row as a result of the increased focus by industry on developing liquids-rich gas pools and higher prices of these NGLs as they track the price of crude oil. Propane, butanes and pentanes plus production increased by 3.6, 5.4, and 9.0 per cent, respectively, in 2013. This is the first significant increase for butanes and pentanes plus production over the past seven years.

Over the forecast period, the supply of propane and butanes is expected to exceed demand. In addition, the decline in production for butanes and pentanes plus in Alberta has been moderating.

Although an increase from last year, the supply of pentanes plus is still tight; therefore, alternative sources of diluent are being used by industry to dilute heavier crudes to meet pipeline quality.[7]

[7] Condensates and upgraded bitumen are two main types of diluent used to lower the viscosity of bitumen for transport in pipelines, although naphtha, light crude oil, and butanes can also be used to enable bitumen to meet pipeline specifications.

Sulphur

Sulphur Reserves

The AER estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2013, to be 117.4 million tonnes, down 3 per cent from 2012. The decrease is due to the reduction in sulphur reserves derived from natural gas reserves and from crude bitumen reserves under active development.

Sulphur Production

There are three sources of sulphur production in Alberta: sour natural gas processing, bitumen upgrading, and crude oil refinement into petroleum products. In 2013, Alberta produced 4.46 million tonnes of sulphur, of which 2.38 million tonnes were derived from sour gas, 2.07 million tonnes from upgrading of bitumen, and just 12 thousand tonnes from oil refining. The total sulphur production in 2013 represents an increase of 2 per cent from 2012 levels due to increased production from upgrading bitumen. Most of Canada's sulphur is produced in Alberta, of which most is shipped outside the province.

Figure 14 illustrates historical sulphur closing inventories at processing plants and oil sands operations and sulphur prices at Free On Board (FOB) Vancouver.[8] When international demand is high, Alberta sulphur blocks are used as an additional source to increase the supply.

Canadian exports in 2013 were 4 million tonnes, a 7 per cent decrease from 2012. Nearly 40 per cent of the exports, 1.58 million tonnes, were sent to the United States in 2013; up from 1.57 million tonnes in 2012.

In 2013, sulphur prices averaged US$104 per tonne, a decrease of about 50 per cent over last year's average price of US$201 per tonne. In 2013, declining demand for sulphur from China, the world's largest sulphur importer, affected domestic Chinese and international prices. Weaker global demand for phosphate fertilizers also exerted downward pressure on the global sulphur price.

Coal

Coal Reserves

The AER estimates the remaining established reserves of all types of coal in Alberta as of December 31, 2013, to be 33.2 billion tonnes (36.6 billion tons). Of this amount, about 69 per cent is considered recoverable by underground mining methods and about 31 per cent is recoverable by surface mining methods. Of the total remaining established reserves, less than 1 per cent is within permit boundaries of mines active in 2013. Alberta's coal reserves represent more than a thousand years of supply at current production levels.

[8] Free On Board Vancouver represents an international pricing point where, after a commodity is loaded on a ship, the liability for and the cost of shipping the commodity transfers from a seller to a buyer.

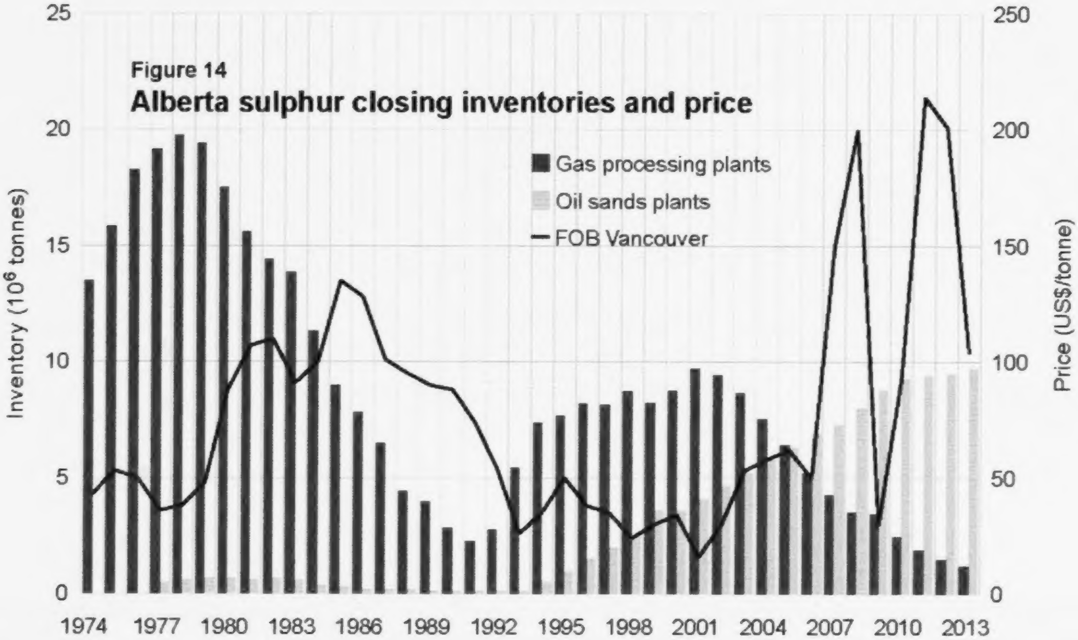


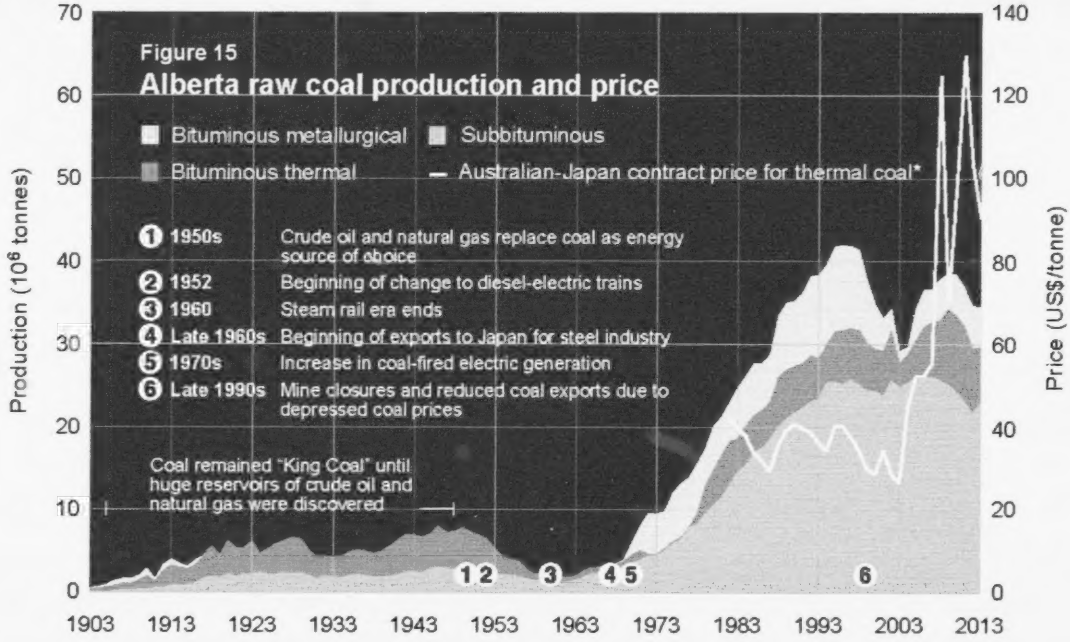
Figure 14
Alberta sulphur closing inventories and price

Coal Production

Alberta's coal production dates back to the 1800s, when coal was used mainly for domestic heating and cooking. Historical raw coal production by type is illustrated in **Figure 15**. The export prices for coal are based on bituminous thermal coal contract prices for Australian coal shipped to Japan (often referred to as Newcastle thermal coal) and are used as a benchmark in this report. Australia is the world's largest exporter of coal. Subbituminous coal produced in Alberta is mainly used in the province for power generation, and cost-of-service contracts with the mining companies generally determine the price.

In 2013, ten mines produced coal in Alberta. These mines produced 29.1 million tonnes of marketable coal. Subbituminous coal accounted for 79 per cent of the total, thermal bituminous coal 11 per cent, and metallurgical bituminous coal the remaining 10 per cent. Overall, total marketable production of coal has increased by 3 per cent relative to 2012, mainly due to the return of some coal fired units to service.

Alberta's metallurgical coal primarily serves the Asian steel industry, with Japan and now China being the leading importers of Alberta coal. Japan also imports the most thermal coal from Alberta. The long distance required to transport coal from mine to port creates a competitive disadvantage for Alberta export-coal producers. However, the demand for metallurgical coal exports increased by 21 per cent in 2013 from 2012, and exports of North American metallurgical coal are becoming more attractive. Consequently, the AER expects a 16 per cent increase in Alberta metallurgical coal production over the forecast period.



*Source: Australian Bureau of Agricultural and Resource Economics.

Electricity

The AER does not publish a perspective on supply and demand for Alberta's electricity sector. Information on electricity, including the market outlook, is provided by the Alberta Electric System Operator (AESO).

Drilling Activity

Figure 16 illustrates the province's drilling history over the past six decades, together with the price of natural gas. Historically, most drilling in Alberta is related to successful gas wells relative to crude oil wells, although this trend reversed in 2011 and continued in 2013. The drilling activity peaked in 2006 and has declined since then. This trend is consistent with industry drilling more horizontal wells and fewer vertical wells in recent years. In general, horizontal wells are now longer than in the 1980s and 1990s. The greater percentage of horizontal wells has significantly increased the average kilometres drilled per well in the last few years. The supporting data for **Figure 16** is represented in **Appendix D**.

Information Graphic

An information graphic summarizing the highlights of 2013 is provided at the end of this report.

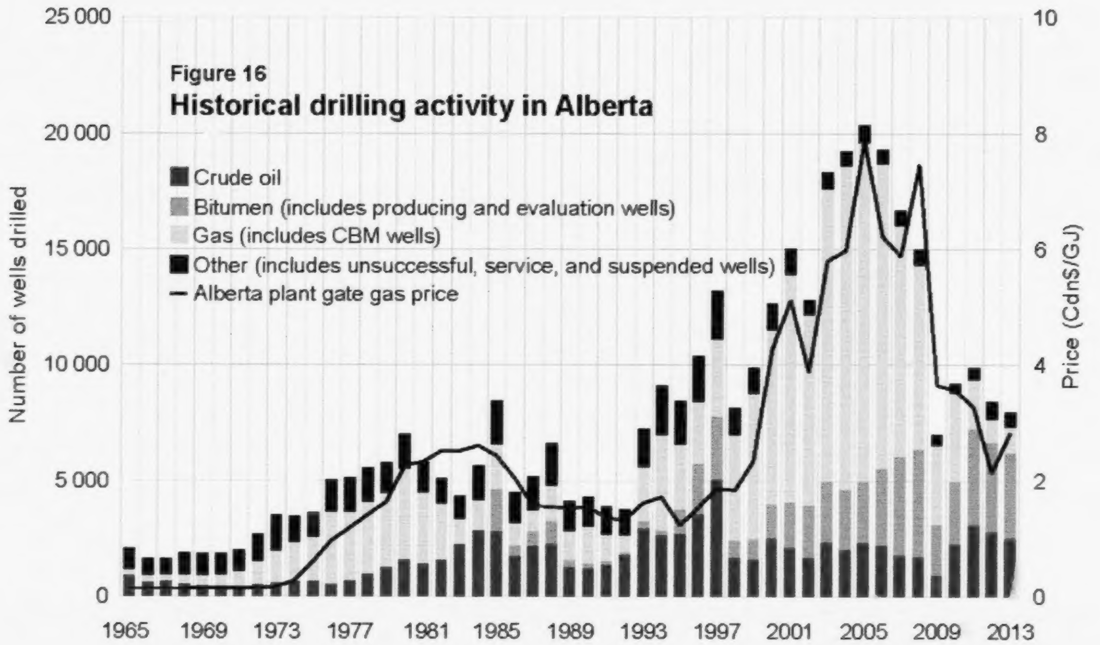


Figure 16
Historical drilling activity in Alberta

1 ECONOMICS

Energy production is determined by energy prices, technology, costs, demand, and remaining reserves. Energy demand, in turn, is determined by such factors as economic activity, standard of living, seasonal temperatures, and population. This section introduces some of the main variables affecting Alberta's energy sector and sets the stage for later discussions in this report.

HIGHLIGHTS

WTI crude oil prices averaged US$98.05 per barrel in 2013, compared with US$94.15 per barrel in 2012, an increase of 4 per cent.

Alberta wellhead natural gas prices averaged $2.83 per gigajoule in 2013, compared with $2.14 per gigajoule in 2012, an increase of 32 per cent.

The value of upgraded and nonupgraded bitumen production averaged Cdn$57.4 billion in 2013, compared with Cdn$51.4 billion in 2012, an increase of 12 per cent.

1.1 Energy Prices

1.1.1 World Oil Market[1]

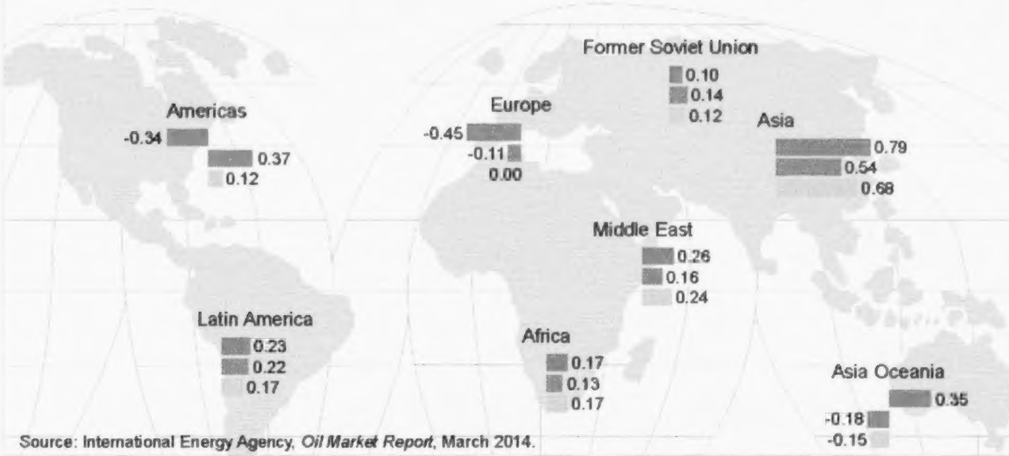
In 2013, average world oil demand rose by 1.3 million (10^6) barrels per day (bbl/d) to 91.33 10^6 bbl/d (14.5 10^6 cubic metres per day [m^3/d]), a 1.4 per cent change from 2012. The International Energy Agency (IEA) reported that average net oil consumption in Organisation for Economic Co-operation and Development (OECD) countries increased by 0.1 10^6 bbl/d (0.02 10^6 m^3/d) to 46.1 10^6 bbl/d (7.3 10^6 m^3/d) and the total in non-OECD countries by 1.2 10^6 bbl/d (0.19 10^6 m^3/d) to 45.3 10^6 bbl/d (7.2 10^6 m^3/d). For the first time since 2010, total OECD demand grew in 2013.

Figure 1.1 illustrates changes in oil demand across the globe in 2012 and 2013, along with the most recent forecast for 2014 by the IEA. The IEA projects that world oil demand will increase by 1.4 10^6 bbl/d (0.22 10^6 m^3/d) in 2014, or 1.5 per cent, to 92.7 10^6 bbl/d (14.7 10^6 m^3/d).

In 2013, the Organization of Petroleum Exporting Countries (OPEC) produced 36.8 10^6 bbl/d (5.9 10^6 m^3/d), compared with 37.6 10^6 bbl/d (6.0 10^6 m^3/d) in 2012. OPEC production in 2013 satisfied about 40 per cent of total world oil demand, down from 41 per cent in 2012. Non-OPEC oil production increased from 53.4 10^6 bbl/d (8.5 10^6 m^3/d) in 2012 to 54.7 10^6 bbl/d (8.7 10^6 m^3/d). In 2013, the world's top three oil producing countries (Russia, the United States, and Saudi Arabia) produced 33 per cent of total oil supply, producing 10.9 10^6 bbl/d (1.7 10^6 m^3/d), 10.3 10^6 bbl/d (1.6 10^6 m^3/d), and 9.4 10^6 bbl/d (1.5 10^6 m^3/d), respectively. This was the first year the United States produced more oil than Saudi Arabia since 2002.

[1] Within this section, "oil" refers to crude oil, condensates, natural gas liquids, refinery feedstocks and additives, other hydrocarbons, and petroleum products. Statistics obtained from the International Energy Agency's *Oil Market Report* (March 2014).

Figure 1.1
Growth in world oil demand 2012–2014 (10^6 bbl/d)



Source: International Energy Agency, *Oil Market Report*, March 2014.

1.1.2 International Oil Prices

Monthly average world oil prices for 2013, represented by the price of Brent Blend (Brent)[2] and the price of West Texas Intermediate (WTI),[3] are shown in **Figure 1.2**. In the first quarter of 2013, Brent prices averaged US$112.49/bbl. Prices then fell in April, reaching a low of US$102.25/bbl. Brent prices in the second half of 2013 recovered and ranged between US$107.79/bbl and US$111.60/bbl, with an annual average of US$108.56/bbl. The WTI price averaged US$98.05/bbl in 2013, reaching a high of US$106.54/bbl in August and a low of US$92.07/bbl in April.

In the first quarter of 2013, crude oil prices strengthened in response to the economic recovery in most countries and continued tension in the Middle East. Prices began to fall in March and reached a low in April on reports of high global crude oil stocks, declining Chinese exports, and renewed fears over another European recession. Prices began to recover in July as supply disruptions and production declines occurred in Libya, Iran, Iraq, and Yemen. By the fourth quarter of 2013, prices began to fall again as China's economy showed signs of slowing down.

Another significant market condition, highlighted in **Figure 1.2**, is the separation between the price of WTI and Brent. WTI began 2013 trading at a US$18.12/bbl discount to Brent. By the fourth quarter, however, the discount had narrowed to US$11.75/bbl, resulting in an average 2013 discount of US$10.51/bbl. While the discount narrowed from the 2012 average of US$17.45/bbl, it continues to reflect the significant increases in North

[2] Brent Blend is a blend of light sweet crude oil from 15 different oil fields in the North Sea. Brent Blend futures are traded on the IntercontinentalExchange, Inc. and are considered a global benchmark for oil prices.

[3] WTI is a light sweet grade of crude oil that is typically referenced for pricing purposes at Cushing, Oklahoma.

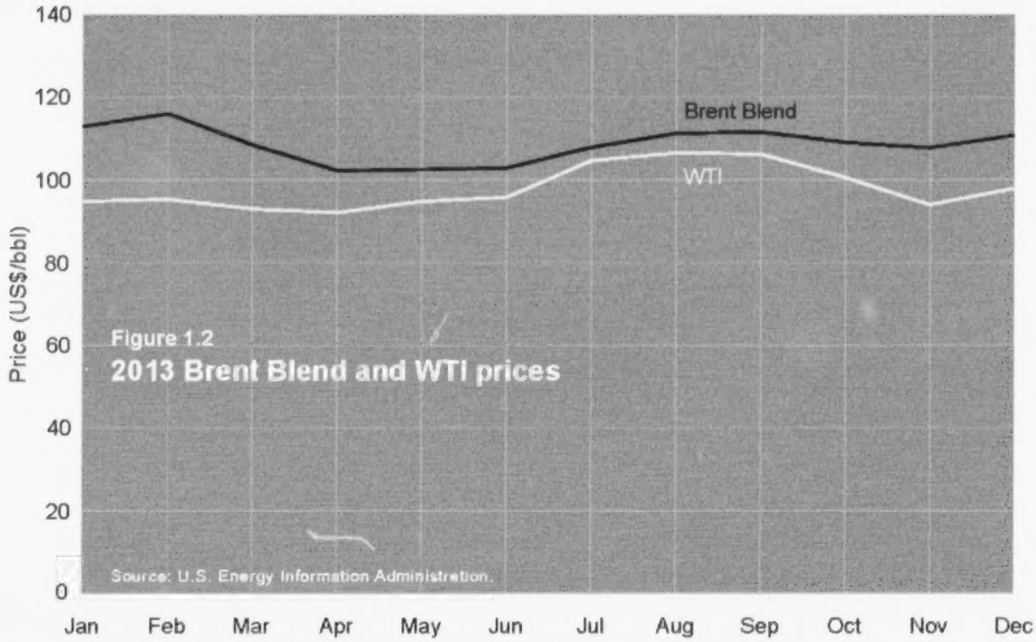


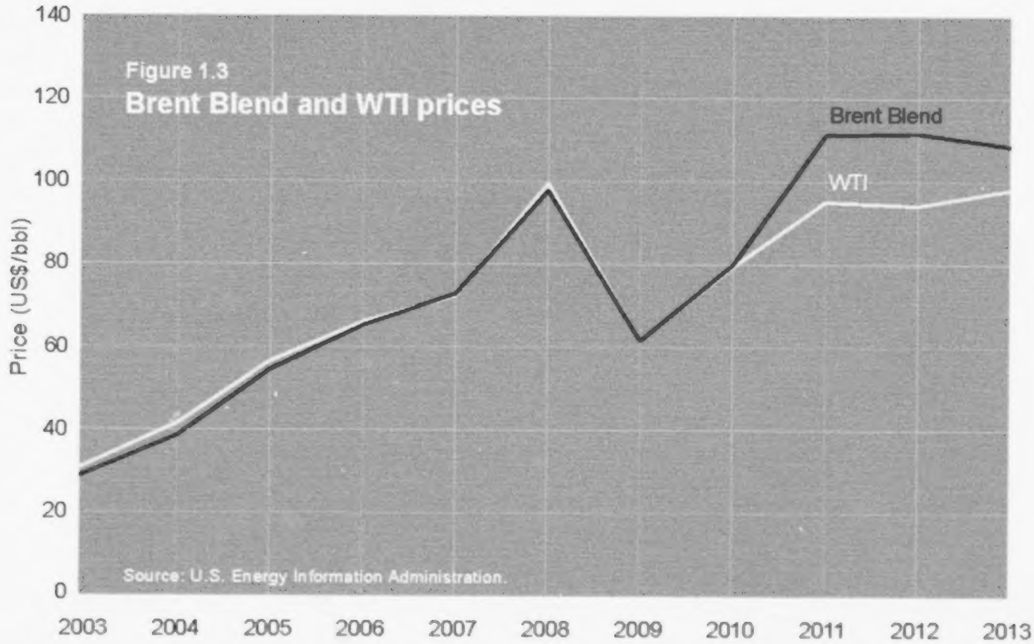
Figure 1.2
2013 Brent Blend and WTI prices

American mid-continent supplies. Mid-continent supplies continue to be relatively high because of continued increases in American and Canadian oil and bitumen production.

U.S. oil production saw another year of record growth. North Dakota light oil production again hit record high production levels in 2013, up 29 per cent over 2012 levels. Texas oil production was again up significantly, reaching 30 per cent over 2012 levels—levels not seen in more than three decades. Production from the Canadian oil sands was also up in 2013, increasing by 8.5 per cent.

Crude oil inventories at the Cushing storage hub, continued to decline throughout 2013 and reached 41.4 10^6 bbls (6.6 10^6 m^3) on December 31, 2013, down 20 per cent from a year ago. Several new crude oil transportation projects came on line in early 2013, including pipelines and crude-by-rail terminals. This new infrastructure helped clear transportation bottlenecks in the U.S. mid-continent, particularly around Cushing. As a result, the price of WTI has strengthened, but still remains lower than other U.S. crude prices, such as Louisiana Light Sweet and Alaska North Slope. Although the transportation constraints have eased, producers are still competing with each other for pipeline space and using more expensive transportation alternatives, such as rail, truck, or barge. Rail transportation is discussed in more detail in **Section 9.1.2**.

Figure 1.3 depicts the yearly average Brent price and the yearly average WTI price from 2003 to 2013. From 2003 to 2006, WTI averaged US$1.09/bbl to $3.21/bbl higher than Brent annually, reflecting differences in quality, the cost of shipping, and localized market conditions. From 2007 to 2009, prices were at or close to par. WTI started to trade at a discount to Brent in 2010, a discount that has continued over the last three years.



1.1.3 North American Crude Oil Prices

North American crude oil prices are based on the price of WTI crude oil at Cushing, which is the underlying physical commodity market for the New York Mercantile Exchange (NYMEX) for light crude oil contracts. WTI crude oil has an American Petroleum Institute (API) gravity of 40 degrees and a sulphur content of less than 0.5 per cent.

As discussed earlier, the significant increase in U.S. domestic crude oil production has been a contributing factor to the WTI discount relative to the Brent price. Unconventional oil production has significantly added to the growth in U.S. supply over the last five years as multistage fracturing completion technology is being used to access crude oil in reservoirs previously considered uneconomic.

As illustrated in **Figure 1.4**, the declining trend in crude oil production in the United States reversed in 2009. Production increased significantly from an average 5.4 10^6 bbl/d (0.86 10^6 m^3/d) in 2009 to 7.45 10^6 bbl/d (1.18 10^6 m^3/d) in 2013, a 39 per cent increase. This average in 2013 is 15 per cent higher than what it was in 2012. This is the highest level of average U.S. production since 1989 and is the largest annual percentage increase since 1940. **Figure 1.4** also shows that U.S. average gas production has also risen in recent years, increasing by 35 per cent from 2005 to 2013.

In North Dakota, crude oil production averaged 858 10^3 bbl/d (136.3 10^3 m^3/d) in 2013, an increase of 29 per cent from 2012 levels. Light crude production from the Bakken Formation accounts for 90 per cent of North Dakota's total oil production, which has surpassed Alberta's conventional crude oil production by nearly 50 per cent. The increased supply of light crude has also depressed Canadian light crude prices because Alberta crude oil is competing with Bakken crude for pipeline space. In Texas, onshore production of crude oil averaged

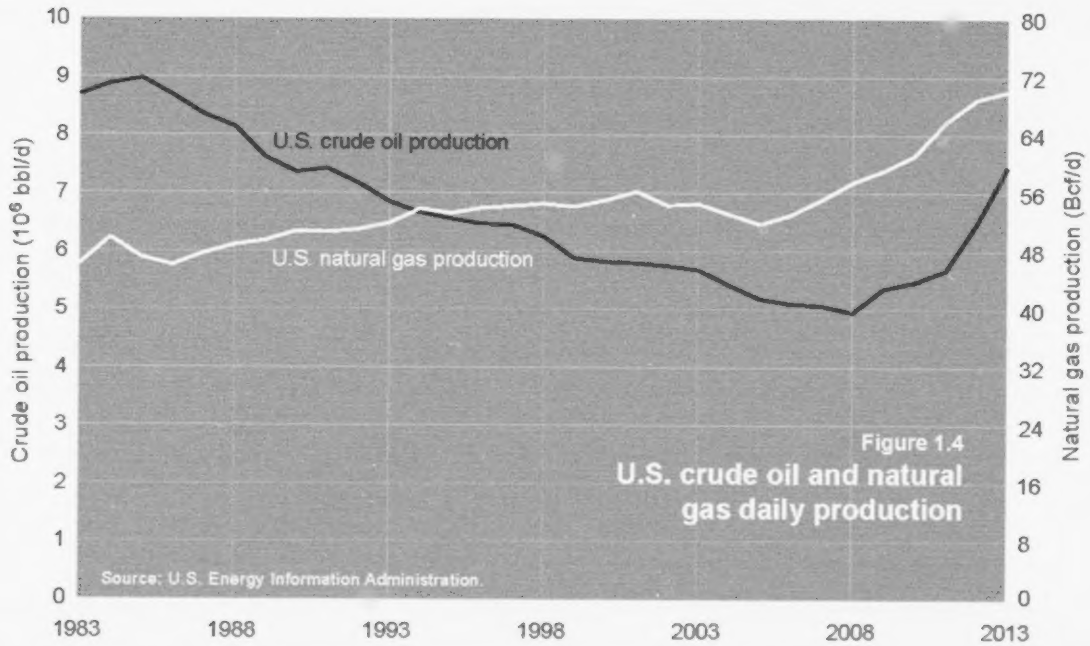


Figure 1.4
U.S. crude oil and natural gas daily production

2578 10^3 bbl/d (409.7 10^3 m^3/d) in 2013, an increase of 30 per cent from 2012 levels. U.S. crude oil production is further discussed in **Section 4.2.1.2**.

In 2013, the WTI price averaged US$98.05/bbl, up US$3.90/bbl from 2012. The AER projects WTI to average US$95.00/bbl in 2014, due to increased North American supply, ranging from US$85.00/bbl to US$105.00/bbl. **Figure 1.5** shows historical and forecast WTI prices at Cushing.

As illustrated in **Figure 1.5**, the AER projects the price of WTI to increase throughout the forecast period. The near-term WTI forecast reflects the expected increase in world oil supply, moderating demand in non-OECD countries, and the continued WTI discount due to pipeline constraints in parts of North America. The long-term forecast reflects expectations that transportation constraints will be alleviated and that current global economic conditions will improve. By 2023, WTI prices are projected to be US$111.81/bbl, ranging from US$86.10/bbl to US$137.23/bbl. This forecast is slightly higher than last year's forecast.

The AER derives light crude oil prices at Edmonton, Alberta, as a function of WTI prices at Cushing. The WTI price is adjusted for transportation and other charges between Edmonton and Cushing, including the exchange rate, as well as for crude oil quality. **Figure 1.6** shows historical prices and the AER's forecast for Alberta light-medium crude oil in Canadian dollars.

Table 1.1 compares 2012 and 2013 Alberta light-medium and heavy crude oil prices. In 2013, the price of light-medium crude oil averaged Cdn$87.77/bbl, up Cdn$5.63/bbl from 2012. The AER projects the price of light-medium crude oil to average Cdn$89.97/bbl in 2014, ranging from Cdn$79.65/bbl to Cdn$100.30/bbl.

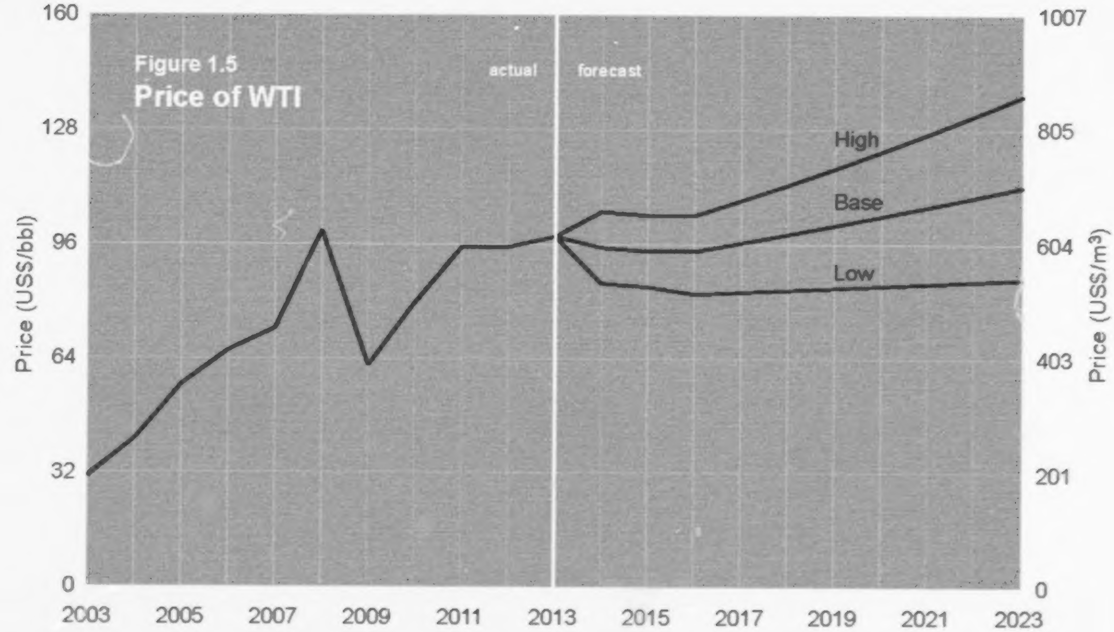


Figure 1.5
Price of WTI
actual
forecast
High
Base
Low
Price (US$/bbl)
Price (US$/m³)
160
128
96
64
32
0
1007
805
604
403
201
0
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023

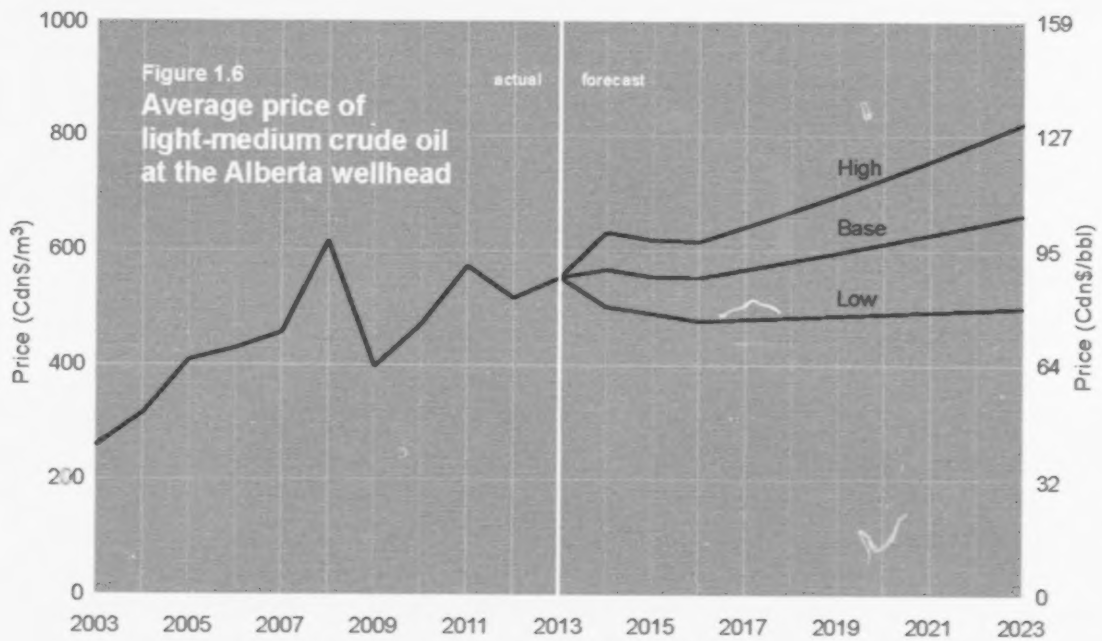


Figure 1.6
Average price of light-medium crude oil at the Alberta wellhead
actual
forecast
High
Base
Low
Price (Cdn$/m³)
Price (Cdn$/bbl)
1000
800
600
400
200
0
159
127
95
64
32
0
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023

Table 1.1 Alberta wellhead annual average crude oil prices[a]

	Average annual price (Cdn$/bbl)	
	2013	**2012**
Alberta light-medium crude oil price	87.77	82.14
Alberta heavy crude oil price	69.07	67.59

[a] Prices are from AER report *ST3: Alberta Energy Resource Industries Monthly Statistics*, which reflect Alberta Petroleum Marketing Commission (APMC) prices. The APMC average price represents the value of the average Crown sales in the province in dollar per cubic metre with respect to royalty oil delivered to the APMC at the field delivery point to which the oil was required to be delivered in that month.

As illustrated in **Figure 1.6**, the forecast price of light-medium crude oil is expected to increase throughout the forecast period and reach Cdn$105.09/bbl in 2023, with a range from Cdn$79.38/bbl to Cdn$130.50/bbl.

In 2013, Alberta light-medium crude oil was priced at a discount relative to WTI due to competition from increased production from the Bakken play in the United States. In the short term, the Alberta light-medium forecast reflects the expectation that light crude oil production will continue to increase in North America. The long-term forecast for Alberta light-medium reflects the expectation that transportation constraints will be alleviated and demand for Canadian crudes will increase.

Figure 1.7 illustrates the average annual price of Alberta light-medium and heavy crude oils. The differential between Alberta heavy and light-medium crudes averaged Cdn$17.66/bbl, or 25 per cent, from 2003 to 2013. Most of this differential is attributable to quality differences between heavy and light-medium crude. The heavy/light-medium differential in 2013 averaged Cdn$18.70/bbl, or 21.3 per cent, compared with $14.55/bbl, or 17.7 per cent, in 2012. The heavy/light-medium differential widened in 2013 as light-medium prices rose due to the increased transportation infrastructure, which includes oil pipelines, truck, and rail, to transport light-medium crude to the United States. The heavy/light-medium differential is expected to average 16.8 per cent over the forecast period, narrower than the most recent five-year average of 17.7 per cent.

The price of heavier Canadian crudes, such as Western Canadian Select (WCS),[4] have shown deeper discounts compared with the price of benchmark light-medium crudes due to concerns about oversupply, especially from the oil sands. In 2013, WCS averaged US$73.01/bbl, similar to the 2012 value of US$73.14/bbl. However, it traded at US$24.96/bbl under the price of WTI, which was US$3.89 more than the 2012 discount of US$21.07 due to a higher WTI price in 2013. The WCS-WTI discount was almost Cdn$7.00 lower than the Cdn$18.30/bbl heavy/light-medium discount. In response to an apportionment[5] on mid-continent pipelines, the discount between WCS and WTI widened to US$37.37/bbl for December, as illustrated in **Figure 1.8**.

Crude oil production in Alberta, after meeting Alberta and Canadian refinery demand, is exported to the United States. The Petroleum Administration for Defence Districts (PADDs) 2 and 4 in the United States are the

[4] WCS is made up of existing western Canadian heavy conventional crude oil and Alberta crude bitumen blended with diluent.

[5] When shippers desire to ship more oil or oil products in a given month than the pipeline can transport, shipper volumes are apportioned (reduced) based on the tariff in effect. Apportionment can be caused by factors such as growing supply, increased demand, pipeline reconfigurations, reduced pipeline capacity, or refinery maintenance.

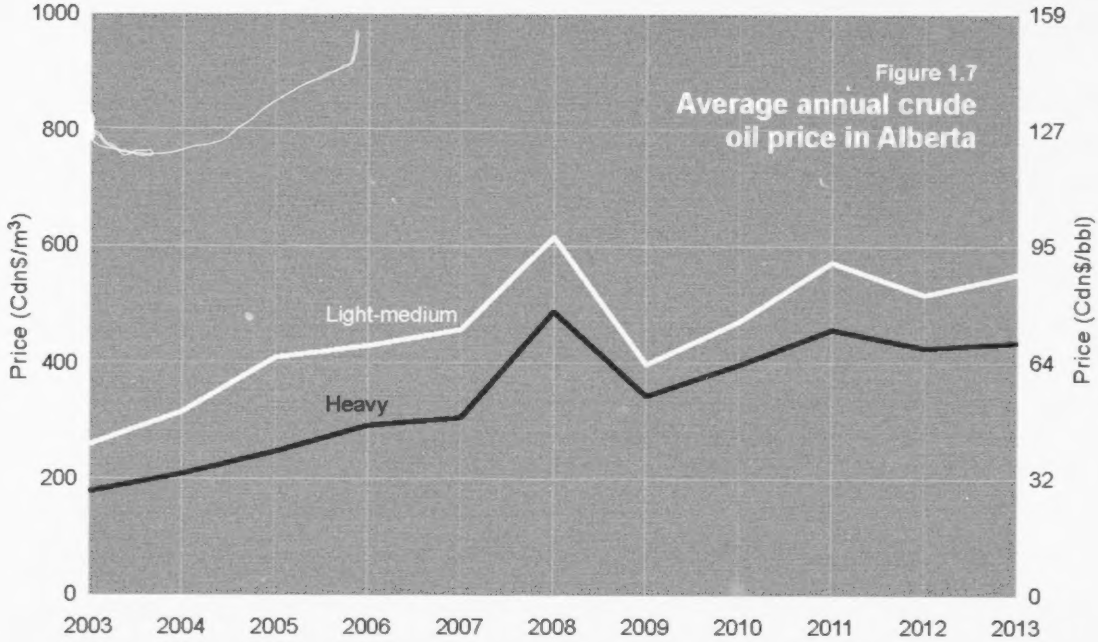


Figure 1.7
Average annual crude oil price in Alberta
Light-medium
Heavy
Price (Cdn$/m³)
Price (Cdn$/bbl)
1000
800
600
400
200
0
159
127
95
64
32
0
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013

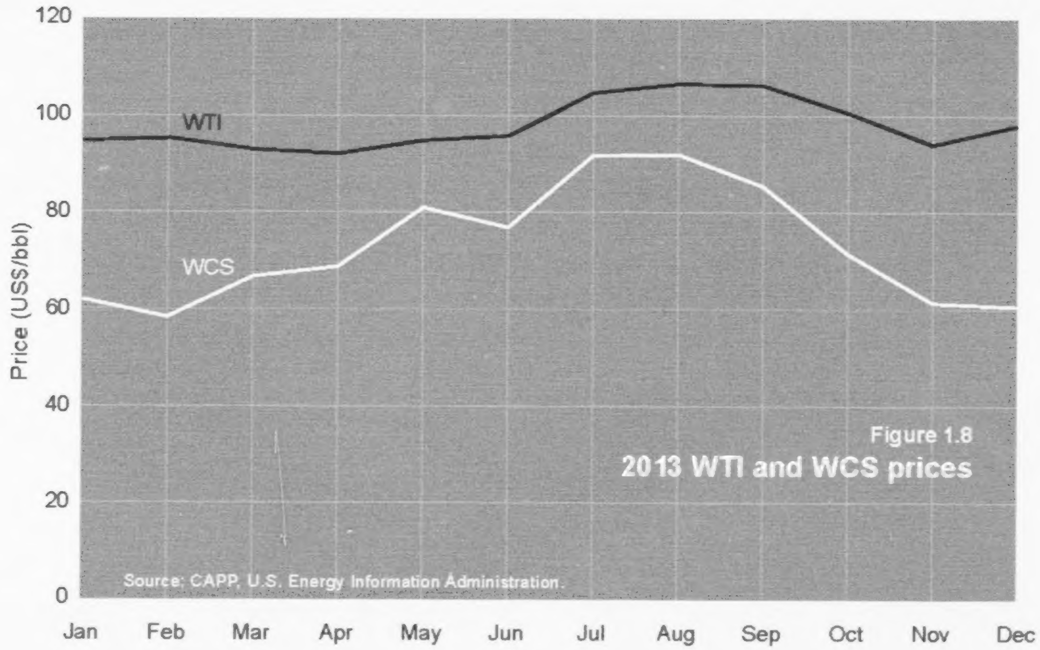


Figure 1.8
2013 WTI and WCS prices
WTI
WCS
Price (US$/bbl)
120
100
80
60
40
20
0
Source: CAPP, U.S. Energy Information Administration.
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

largest importers of Alberta heavy crude and bitumen, with a combined total refinery capacity of 4130 10^6 bbl/d (656 10^3 m^3/d). Increased heavy oil upgrading capabilities at the BP America Inc. (BP) refinery at Whiting, as well as other refinery conversion projects, will increase PADD 2 and PADD 4 capacities to take on increasing amounts of Alberta heavier crudes.

Although no new refineries have been built since the 1970s, the total refinery capacity in the United States increased slightly during the 1990s and 2000s because of debottlenecking and the expansion of existing refineries. This trend has continued with U.S. refining capacity increasing by 2.9 per cent between January 1, 2012, and January 1, 2013, according to the Energy Information Administration (EIA). This increase in capacity caused a slight increase in Canadian heavy crude prices in the second quarter of 2013.

There are also two new refineries in the works. A 20 10^3 bbl/d refinery in North Dakota is already under construction and Houston-based Rock River Resources announced a 10 10^3 bbl/d refinery, which it expects to be operational in mid-2015.

Additional pipeline infrastructure is important to provide an avenue for increasing Alberta heavy crude exports to new or expanding markets in the United States and Asia. With expected increases in both upgraded and non-upgraded bitumen supply over the forecast period, adequate incremental pipeline capacity is essential to transport growing volumes to market. Pipeline projects are discussed in **Section 9.1.1**.

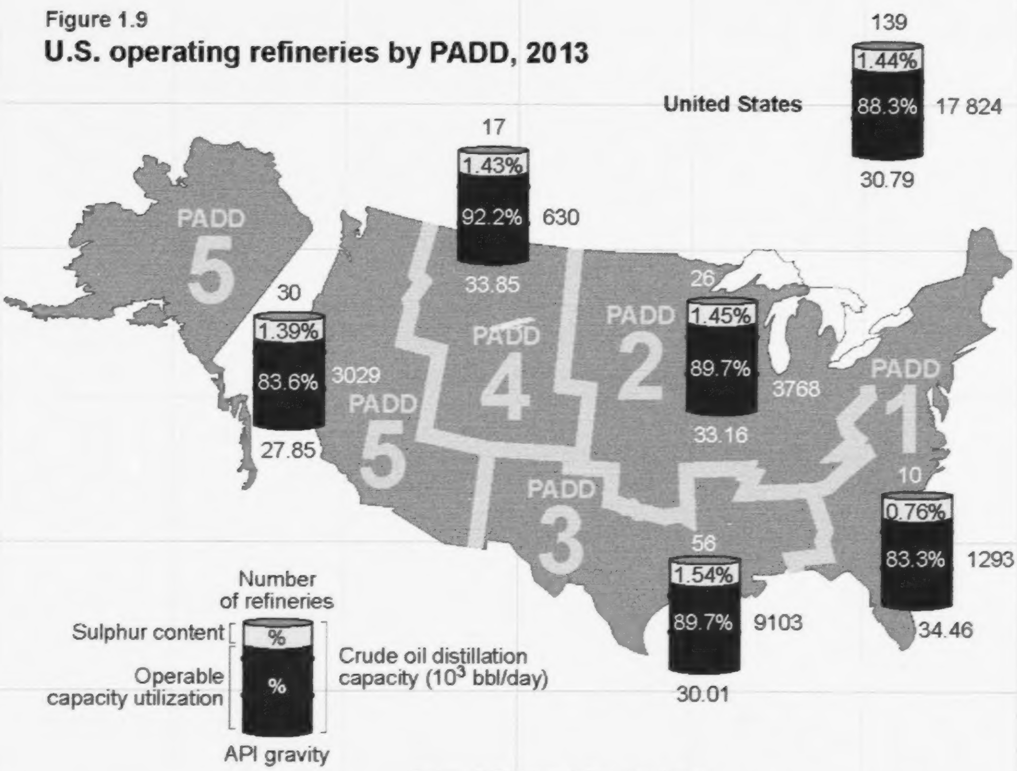
Figure 1.9 provides information on U.S. refineries by PADD. PADD 3 has the largest refinery capacity in the United States, with 56 operating refineries and a net crude oil distillation capacity of 8.7 10^6 bbl/d (1387 10^3 m^3/d). PADD 3 was not previously viewed as the most likely market for Alberta crude oil because of inadequate pipeline infrastructure and its proximity to Mexican and Venezuelan crude oil production. However, traditional crude oil inputs to PADD 3 have been on the decline, suggesting a significant market opportunity for Alberta heavy crude oil producers. As a result, projects such as TransCanada Corporation's Keystone XL project are expected to increase pipeline capacity to the area.

1.1.4 North American Natural Gas Prices

The long-term outlook for U.S. gas supply has changed with the growth in supply from shale gas. As illustrated previously in **Figure 1.4**, following a four-year period of decline between 2001 and 2005, natural gas production in the United States began to increase significantly. Total U.S. marketed gas production was 70.0 billion cubic feet per day (bcf/d) (2.0 billion [10^9] m^3/d) in 2013, a 35 per cent increase from 2005 levels.

Increased U.S. natural gas production has resulted in low natural gas prices, as shale gas production has more than offset production declines from conventional resources and has exceeded demand growth in the United States. Projects to convert some of the liquefied natural gas (LNG) regasification terminals to liquefaction terminals are occurring to enable exports of domestic natural gas supplies to markets offering higher prices. In addition, new LNG export terminals have been proposed in both the United States and Canada.

Figure 1.9
U.S. operating refineries by PADD, 2013

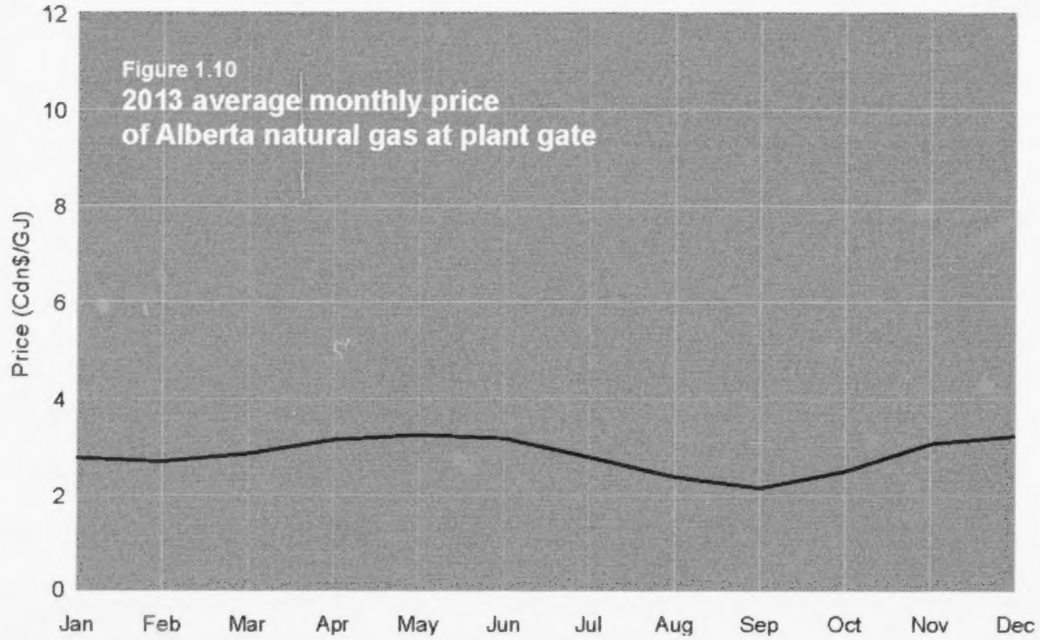


Source: U.S. Energy Information Agency.
Number of operating refineries as of February 28, 2014. Data for the year 2013.
Sulphur content and API gravity are weighted averages.

In Canada, several LNG export projects have been proposed on the coast of British Columbia (B.C.) as Canadian natural gas producers reach for new gas markets in Asia. Under increased competition from U.S. shale gas production, U.S. natural gas imports from Canada have fallen by 26 per cent since 2007. Asian markets, with natural gas prices linked to crude oil prices, provide an attractive alternative to U.S. exports. As of early 2014, the National Energy Board (NEB) had issued export licences for the Kitimat LNG Operating General Partnership, B.C. LNG Export Co-operative LLC, and LNG Canada Development Inc. and had approved five other projects to export LNG from the B.C. coast to Asia-Pacific markets.

While North American crude oil prices have historically tracked international prices, natural gas prices in North America tend to reflect North American supply and demand, with little influence from the global gas market aside from that of LNG imports. As Alberta natural gas prices are heavily influenced by the Henry Hub U.S. market price, the Alberta price forecast for natural gas was derived from the Henry Hub price, taking into account transportation differentials and the exchange rate.

Figure 1.10 shows the monthly average price of Alberta natural gas at the plant gate (also known as the Alberta reference price) in 2013. In the first half of 2013, natural gas prices rose to Cdn$2.98 per gigajoule (GJ) as a



result of increased demand. Prices then fell to a low in September of Cdn$2.14/GJ, mainly due to the increase in storage levels in Alberta. Colder than normal temperatures in North America resulted in a rebound in December with prices averaging Cdn$3.22/GJ. The average Alberta reference price for natural gas in 2013 was Cdn$2.83/GJ, compared with Cdn$2.14/GJ in 2012, a 32.2 per cent increase. In 2013, U.S. natural gas prices at Henry Hub increased by 31.8 per cent compared with 2012 levels.

Figure 1.11 shows the historical and forecast average price of Alberta natural gas at the plant gate. The AER projects a base price of Cdn$3.84/GJ for natural gas at the Alberta plant gate, due to increasing demand, ranging between Cdn$2.89/GJ and Cdn$4.79/GJ in 2014. Over the forecast period, the price of natural gas is projected to increase and reach an average of Cdn$5.90/GJ by 2023, ranging from Cdn$3.98/GJ to Cdn$7.40/GJ. The forecast in this report is an increase over last year's forecast.

The forecast assumes that continued shale gas production in the United States will keep prices low in the short and medium term. Additional demand for natural gas will arise from environmental incentives to switch fuel for electricity generation and, in the short term, price incentives. Longer term, LNG export projects are expected to add additional demand.

The Alberta price ratio[6] of gas to light-medium oil, on an energy content basis, averaged 0.49 from 2003 to 2012. In 2013, the price ratio averaged 0.20, compared with 0.16 in 2012. Over the forecast period, the gas-to-oil price ratio is projected to average 0.31, as North American gas prices are projected to increase slowly relative to crude oil prices.

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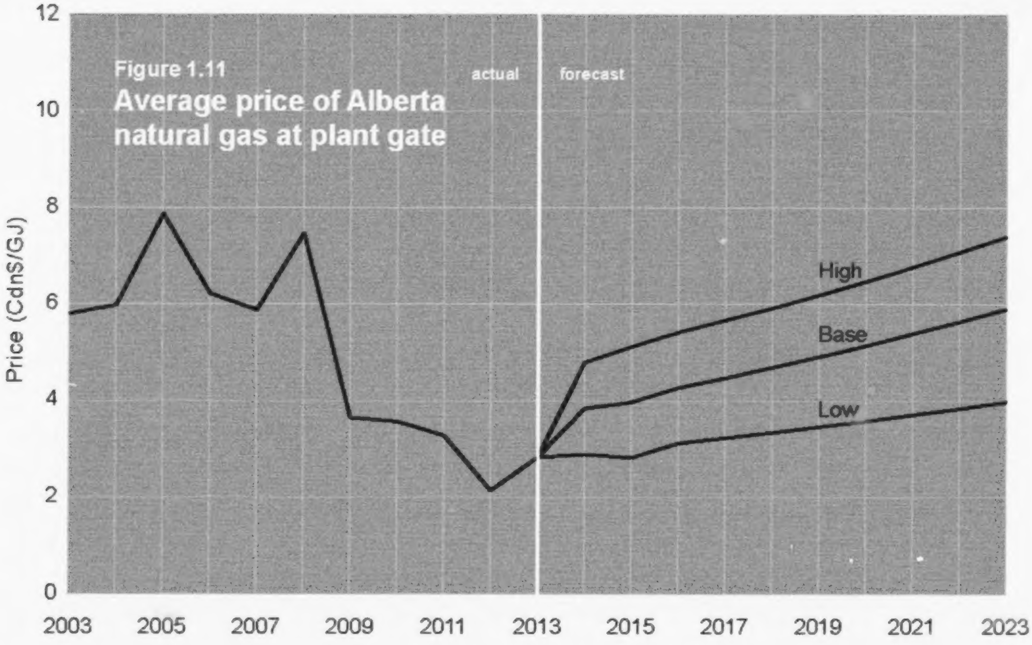
[6] If consumers were to pay the same price for a unit of gas as they would for a smaller unit of light-medium crude oil containing the same energy content as the unit of gas, the gas to light-medium price ratio would be 1.00 (parity being achieved). However, for a variety of reasons, oil is intrinsically valued higher than gas and the price ratio is often near or above 0.50.



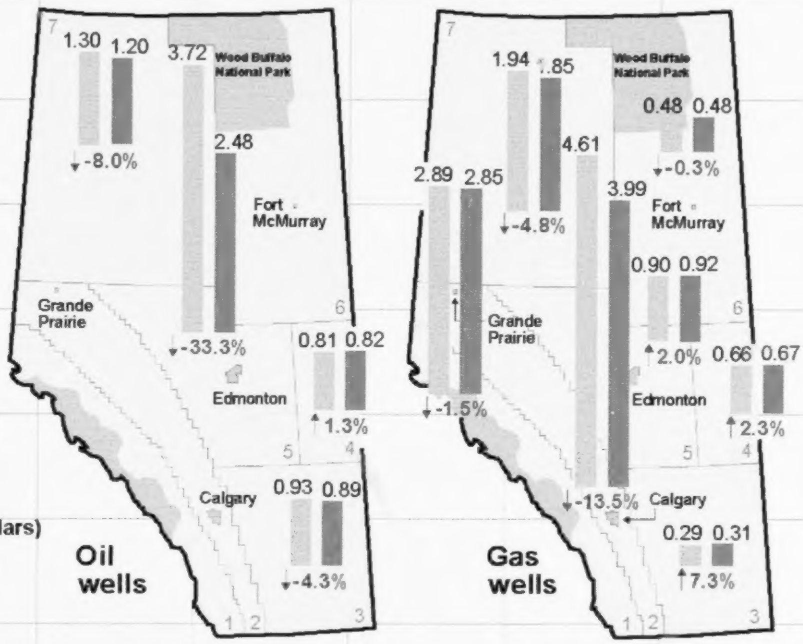
1.2 Oil and Gas Drilling and Completion Costs in Alberta

For over 30 years, the Petroleum Services Association of Canada (PSAC) has been providing cost estimates for typical oil and gas wells for the upcoming drilling season. PSAC defines a typical oil and gas well as a well that reflects the most common well type to be drilled in 2014 in western Canada. The cost estimates in **Figure 1.12** were obtained from PSAC's *2014 Well Cost Study*. **Table 1.2** outlines the median well depth for each area, a major contributor to drilling costs. Many other factors influence well costs, including the economic environment, the type of commodity produced, the type of well (development versus exploratory), surface conditions, the type of production (sweet versus sour), drilling programs, well location, nearby infrastructure, and completion method.

As illustrated in **Figure 1.12**, the estimated cost to drill and complete a typical oil well decreased from the previous year. The estimated cost of drilling and completing a typical oil well in the winter of 2013–2014 ranged from as low as $0.82 million in PSAC Area 4 (East-Central Alberta) to as high as $2.48 million in PSAC Area 5 (Central Alberta). According to PSAC data, an average vertical oil well in PSAC Area 3 (Southeastern Alberta) cost $0.89 million. Completion costs, in PSAC Area 3, represented 47.9 per cent of total drilling and completion costs. For an average horizontal well located in PSAC Area 5, completion costs represented 69.9 per cent of total drilling and completion costs. Of total completion costs, completion fluids represented 43.9 per cent. The average estimated cost to drill and complete an oil well across the PSAC areas decreased by an average 11.1 per cent from the previous year.

Gas well drilling and completion costs are also projected to decrease. Estimated costs to drill and complete a typical gas well in the winter of 2013–2014 were highest in PSAC Area 2 (Foothills Front) at $3.99 million. In PSAC Area 3 (Southeastern Alberta), a typical gas well was estimated to cost $310 000 to drill and complete.

Figure 1.12
Alberta well cost estimations by PSAC area
(millions of current dollars)



2012 (November)
2013 (November)
% percentage change in costs

Drilling, casing, and completion cost estimates (PSAC November 2012 and November 2013 well cost studies).

Table 1.2 Alberta median well depths by PSAC area, 2013 (m)[a]

	Area 1	Area 2	Area 3	Area 4	Area 5	Area 6	Area 7
Gas wells							
Horizontal	3 656	2 550	1 301	667	1 997	258	2 129
Vertical	3 259	2 523	662	714	1 033	508	800
Oil wells							
Horizontal	2 426	1 930	960	752	1 371	596	1 473
Vertical	2 397	2 052	1 053	784	1 576	651	1 629

[a] PSAC defines the areas in Alberta as AB1, AB2, etc. and are referred to as Area 1, Area 2, etc., in this report. The PSAC area map is in Appendix A.2.

According to PSAC data, completion costs for an average vertical well in PSAC Area 3 represented 44.2 per cent of total drilling and completion costs. For an average horizontal well located in PSAC Area 1 (Foothills), completion costs represented 42.8 per cent of total drilling and completion costs, and completion fluids represented 55.2 per cent of completion costs. The average estimated cost to drill and complete a typical gas well across the PSAC areas decreased by an average 1.2 per cent from the previous year.

1.3 Economic Performance

1.3.1 Alberta and Canada

Figure 1.13 depicts the historical performance of major economic indicators for Alberta and Canada. Alberta real gross domestic product (GDP) growth has mostly outperformed Canadian real GDP growth over the past decade, particularly from 2003 to 2006. Average Alberta GDP growth from 2003 to 2013 was 3.2 per cent, compared with a Canadian average of 1.9 per cent. Over the same period, the unemployment rate in Alberta averaged 4.7 per cent while the Canadian unemployment rate averaged 7.1 per cent.

The higher growth and employment levels in Alberta put pressure on the Alberta economy, which resulted in higher levels of inflation. Since 2003, inflation in Alberta has averaged 2.4 per cent per year, while Canadian inflation has averaged 1.9 per cent. In 2013, Alberta inflation averaged around 1.4 per cent compared to 1.1 per cent in 2012.

Figure 1.14 illustrates the historical performance of the U.S./Canadian dollar exchange rate between 2003 and 2013. The exchange rate is an economic parameter that affects both the Canadian and Alberta economies.

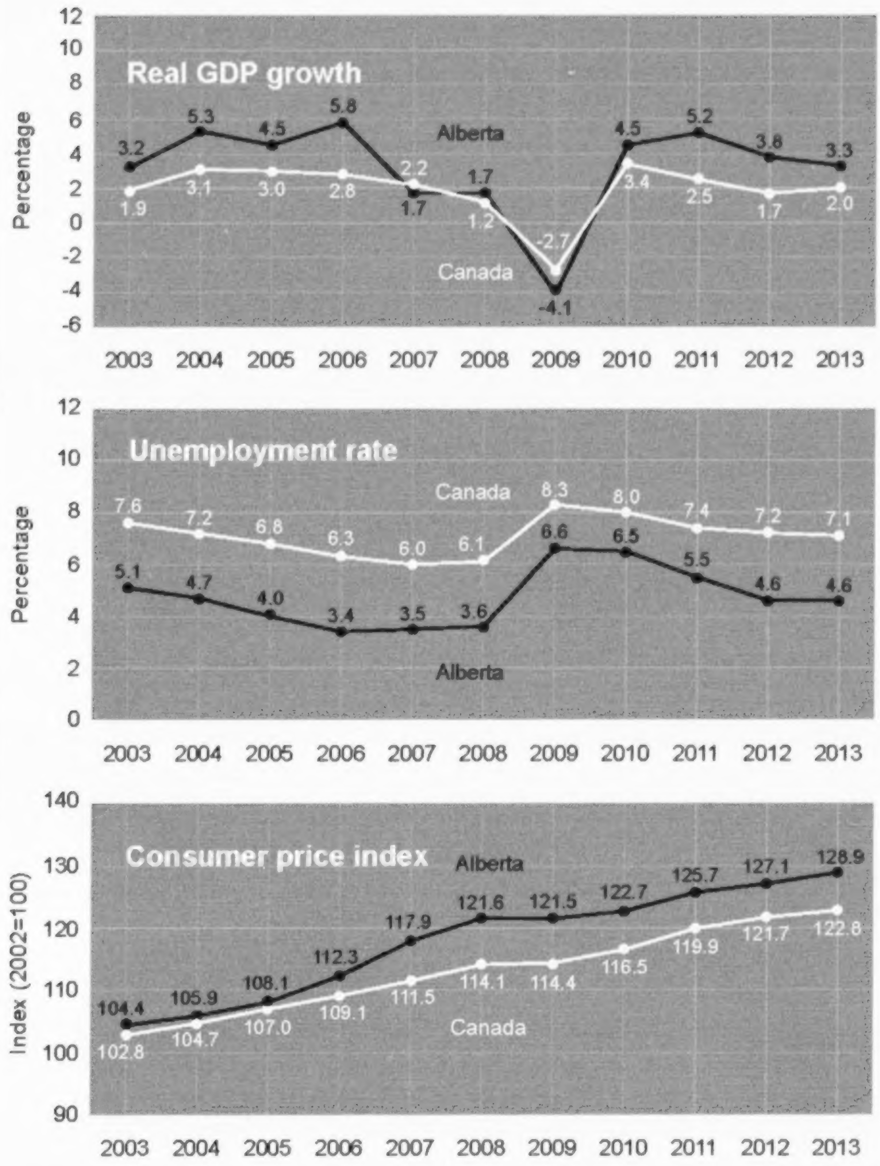
The U.S./Canadian dollar exchange rate averaged US$0.97 in 2013, compared with US$1.00 in 2012. The exchange rate began 2013 with an average of US$1.00 in January and ended with an average of US$0.94 in December—a continued decline. The U.S./Canadian dollar exchange rate is projected to average US$0.92 in 2014, increase to US$0.93 in 2015, and then rise to and remain at US$0.95 for the rest of the forecast period. The forecast in this report is slightly lower than the AER's forecast in the previous report.

Throughout 2013, the Bank of Canada kept the bank interest rate at 1.00 per cent, partially due to its concern over Canadian household debt. Rising interest rates could trigger financial instability, increasing the potential for personal bankruptcies and home foreclosures.

1.3.2 The Alberta Economy in 2013 and the Economic Outlook

The AER forecast of Alberta real GDP and other economic indicators is shown in **Table 1.3**. Alberta real GDP is estimated to have increased by 3.3 per cent in 2013, compared with 3.5 per cent in 2012. Real GDP is forecast to increase by 3.4 per cent in 2014 and to continue to grow by 3.0 per cent from 2015 to 2023 based on expected strong hydrocarbon development and exports. Alberta's inflation rate was 1.4 per cent in 2013, compared with the national inflation rate of 0.9 per cent.

Figure 1.13
Alberta and Canada economic indicators



Source: Statistics Canada.

Alberta's economy is projected to grow in 2014 due to the increased oil and gas activity and increased residential and business investment.

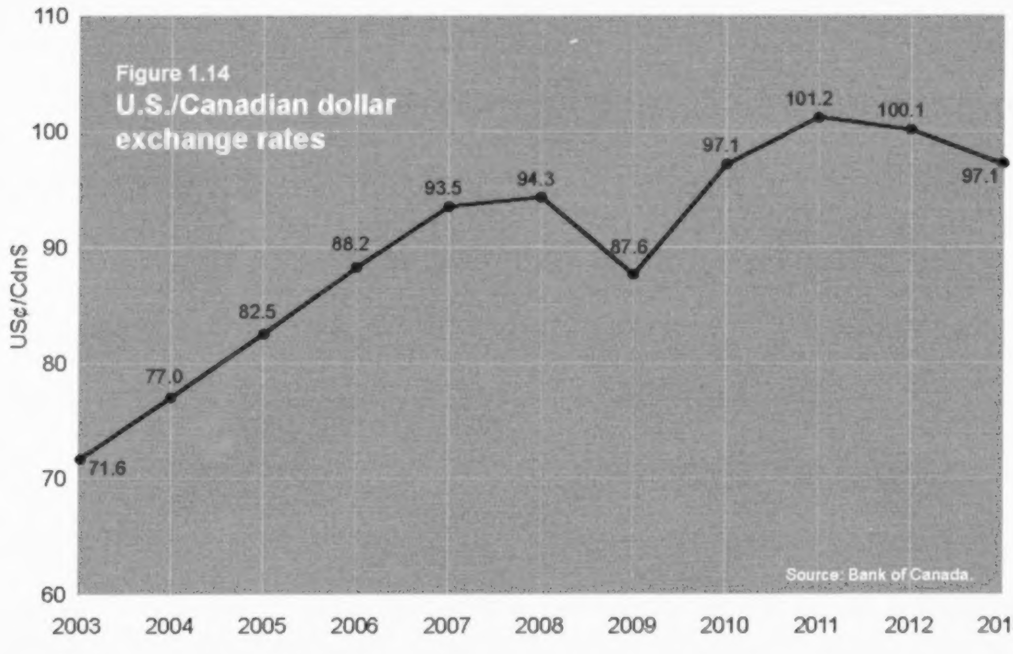
The AER estimates that oil sands capital expenditures decreased to $24.2 billion in 2013, compared with $27.2 billion in 2012. Investment is predicted to decrease to $23.7 billion in 2014 and peak in 2016 at $30.5 billion. In 2013, some oil sands companies announced that they were cutting their capital budget spending and delaying the development of upcoming projects as a result of increased pressure from lower cost conventional oil development in Canada and the United States.

Conventional oil and gas expenditures have rebounded significantly since the 2009 level of $12 billion and reached $26.1 billion in 2012 as activity in conventional basins has shifted to the application of capital-intensive horizontal wells and multistage fracturing. Conventional oil and gas expenditures are estimated to have decreased to $25.1 billion in 2013. Investment in conventional oil and gas is expected to increase over the forecast period as producers continue to use the more costly horizontal wells and multistage fracturing technology.

Table 1.3 Major Alberta economic indicators, 2013–2023 (%)

	2013	2014	Average over 2015–2023[a]
Real GDP growth	3.3	3.4	3.0
Population growth	3.9	2.5	1.8
Inflation rate	1.4	2.0	2.4
Unemployment rate	4.6	4.5	4.4

[a] Average over 2015–2023.



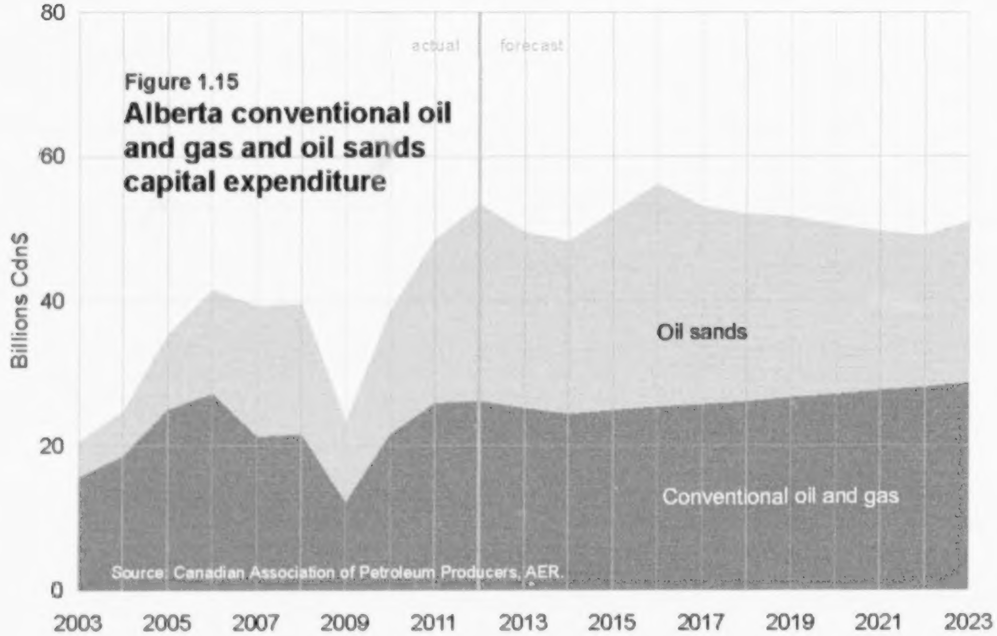


Figure 1.15 profiles the historical and projected investment in Alberta's conventional oil and gas industry and in the oil sands industry.[7] The sharp decline in 2009 was followed by an immediate rebound in 2010. This rebound in conventional oil and gas spending occurred in a relatively mature oil and gas basin in an environment of depressed gas prices.

The AER's forecast of capital spending for oil sands is consistent with forecast projects considered for the upgraded and nonupgraded bitumen production forecast. The conventional oil and gas capital investment forecast is based on historical costs for geological and geophysical analysis, land, facilities, and field equipment.

As shown in **Figure 1.15**, oil sands-related expenditures are projected to increase by the middle of the decade to fulfill the anticipated increases in upgraded and nonupgraded bitumen production. Combined with the recovery in conventional oil and gas expenditures, total oil and gas investment is projected to exceed the levels of capital spending experienced during the 2006–2008 peak.

During the forecast period, nonupgraded bitumen production is forecast to increase at an average annual rate of 9 per cent. Upgraded bitumen production is projected to increase at an average annual rate of 3 per cent. Virtually all of this crude bitumen production increase will leave the province, providing export-led economic growth in Alberta.

The value of Alberta's energy resource production for 2009 to 2013 is depicted in **Figure 1.16**. In 2013, the total value of production increased by 13 per cent relative to 2012. Additionally, the total value of Alberta's energy

[7] Historical statistics obtained from the Canadian Association of Petroleum Producers (CAPP) *Statistical Handbook* (2012 data). Capital expenditures for 2013 are estimates.

resource production increased by 51 per cent relative to 2009 levels. The value of upgraded and nonupgraded bitumen production has significantly exceeded the value of natural gas production, a trend that is expected to continue throughout the forecast period. Since 2009, the value of upgraded and nonupgraded bitumen production has increased by 98 per cent, whereas the value of natural gas production has decreased by 35 per cent. In 2013, combined upgraded and nonupgraded bitumen revenues were 50 per cent greater than the combined revenues from conventional gas, conventional crude oil, natural gas liquids, and sulphur.

The total economic value of Alberta's energy resource production for 2013 to 2023 is shown in **Table 1.4**. Production from upgraded and nonupgraded bitumen derived from the oil sands will more than offset the anticipated decline in conventional resource production, increasing from 60 per cent of total revenues in 2013 to 73 per cent of total annual revenues by 2023.

Based on the projected price and production forecasts, investment in mining, upgrading, and in situ bitumen projects will continue to drive Alberta's production and export growth and the overall Alberta economy. In turn, Alberta's economic growth will continue to contribute strongly to Canada's economic growth.

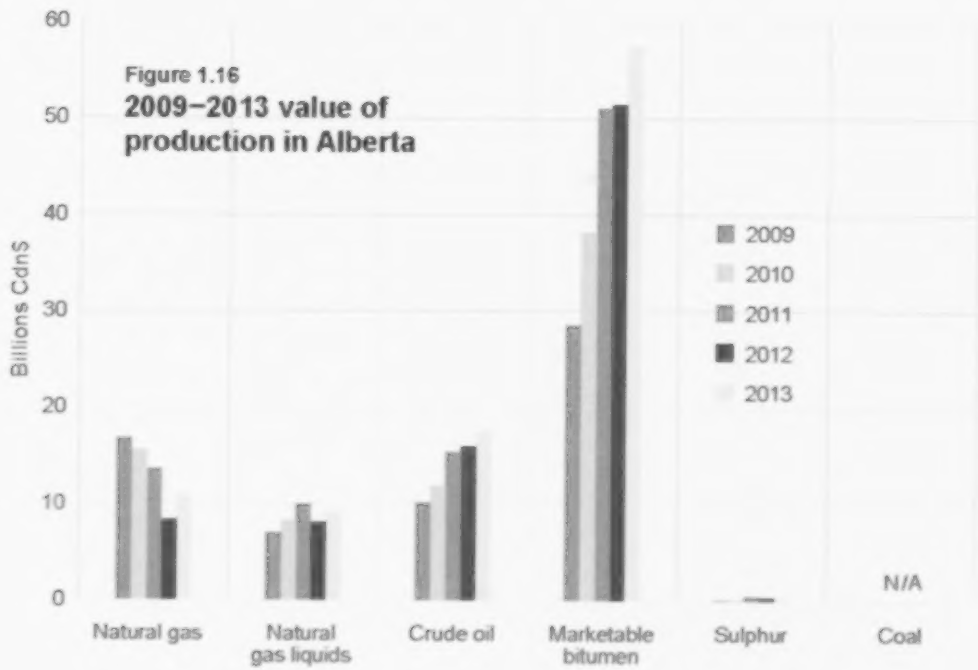


Table 1.4 Value of annual Alberta energy resource production (millions of current dollars)

	2013	2014[a]	2015[a]	2023[a]
Conventional crude oil	17 605	18 169	17 645	17 428
Nonupgraded bitumen	23 520	30 089	33 322	75 978
Upgraded bitumen	33 850	35 616	35 677	55 321
Marketable gas	10 839	14 233	14 373	19 571
Natural gas liquids	9 311	9 957	9 628	11 522
Sulphur	251	286	288	320
Coal[b]	n/a	n/a	n/a	n/a
Total	**95 376**	**108 350**	**110 933**	**180 140**

[a] Values calculated from the AER's annual average price and production forecasts; columns may not add up due to rounding.

[b] Not available (n/a) – There are no publicly available coal prices in Alberta. However, it is believed that coal's value is more similar to sulphur than the other commodities.

2 RESOURCE ENDOWMENT

HIGHLIGHTS

A discussion of the geological framework of the Western Canada Sedimentary Basin.

A discussion of Alberta's petroleum systems.

The methods the AER uses to estimate resources and determine reserves.

The ultimate potential estimate for the Montney Formation.

The reserves framework employed in the report.

Of Alberta's many natural resources, this report focuses on energy resources—namely, petroleum hydrocarbons and coal. The AER performs an appraisal of these resources to fulfill its legislated mandate to provide information regarding the energy resources of Alberta. This resource appraisal includes the major components of geological survey, resource estimation, and reserve determination—all of which are done in a framework that provides consistent year-to-year comparisons of energy development in Alberta.

2.1 Geological Framework of Alberta[1]

The geology of Alberta consists of a northeast-thinning wedge of sedimentary rock lying overtop a crystalline basement of igneous and metamorphic rock of Precambrian age that forms the foundation of the modern North American continent.[2] The thickness of the sedimentary wedge tapers from a thick package thousands of metres in eastern British Columbia (B.C.) to zero in northeastern Alberta where the crystalline basement is exposed as part of the Canadian Shield. Sedimentary rocks also extend into Saskatchewan, Manitoba, the Northwest Territories, and the United States.

2.1.1 Western Canada Sedimentary Basin

Within Alberta, the sedimentary wedge comprises three thick packages of rock most simply described as a carbonate succession sandwiched between two clastic successions. The lower clastic succession is restricted to the Rocky Mountains. It is composed of a thick package of metamorphic quartzite and slate rocks of Precambrian age and overlying sedimentary strata of Cambrian to Ordovician age. The middle carbonate succession is composed mainly of limestones, dolostones, and evaporites of Devonian to Mississippian age. The upper clastic succession is Triassic to Tertiary in age.

Both the middle carbonate and the upper clastic successions cover most of Alberta. Just beneath the modern land surface is a major unconformity that separates the youngest bedrock from gravels, thick glacial deposits, and modern alluvium.

[1] The *Geological Atlas of the Western Canada Sedimentary Basin* contains a full description of Alberta's geological history and forms the basis for the summary in this section. The atlas is available through the AER's Alberta Geological Survey, a co-sponsor of the atlas.

[2] The crystalline basement is the North American craton (Laurentia) and is commonly referred to as the Precambrian Shield in western Canada. Laurentia was created almost two billion years ago by the amalgamation of older continents; some from the Earth's original crust that formed about four billion years ago.

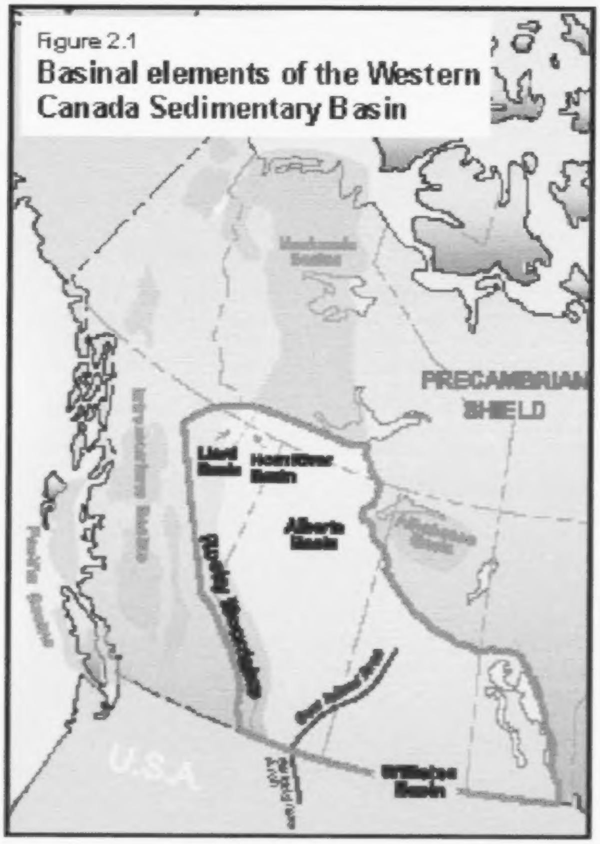


Figure 2.1
Basinal elements of the Western Canada Sedimentary Basin

The initial continental margin and later structural trough that received sediments that comprise these three thick packages are collectively known as the Western Canada Sedimentary Basin (WCSB). The WCSB is often divided into regional basinal and sub-basinal elements, including the Alberta Basin, the Williston Basin, and the Liard/Horn River Basin, as shown on **Figure 2.1**.

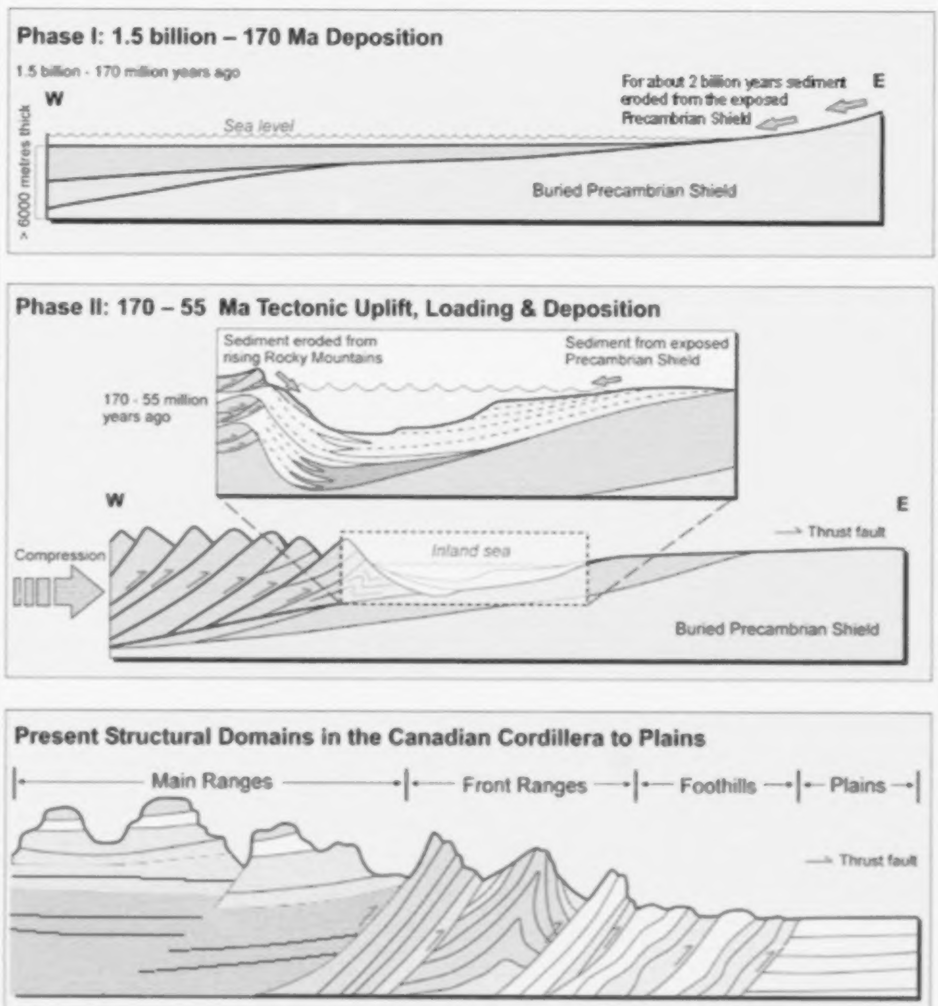
The geological origin and structure of Alberta's strata ultimately determine the type and extent of Alberta's energy resources. The overall geological history of Alberta falls into two main phases:

- Phase I lasted from about 1.5 billion years ago to about 170 million years ago. It was characterized first by deposition in a shallow sea lying along the passive continental margin of the proto-Pacific ocean.[3] This was followed by deposition within a shallow, interior continental seaway. This seaway marked the formation of an intracratonic basin, formed indirectly in association with uplift and mountain building far to the southwest of Alberta. The lower clastic and middle carbonate successions were deposited during phase I.

[3] During phase I, the continental mass (Laurentia) alternated between being a separate continent and existing as part of larger "supercontinents."

- Phase II started about 170 million years ago and continues to the present day. It is characterized by uplift and structural deformation, which formed the Rocky Mountains and mountain ranges farther west. Loading of the mountains onto the crust caused the shallow seaway of phase I to deepen into a depositional trough called a foreland basin. Sediments from the rising mountains were shed eastward into the basin, gradually filling it in and causing the seas to retreat. Uplift abated about 55 million years ago, and the Alberta basin has undergone erosion ever since, with the exception of deposition related to glacial advances and retreats over the last two million years. The upper clastic succession was deposited during phase II. These events are shown in **Figure 2.2**.

Figure 2.2
Geological evolution of Alberta



* Drawings not to scale.

The geological record of events in phases I and II is preserved in the strata of the WCSB. A simplified version of Alberta's strata is shown in **Figure 2.3**. The stratigraphy is formalized in the AER's table of formations, available on the AER's website.

2.1.2 Alberta's Petroleum Systems

Petroleum is a naturally occurring organic mixture consisting predominantly of chain and ring molecules of carbon and hydrogen, with varying amounts of sulphur, nitrogen, and oxygen as impurities. Petroleum forms underground by the action of heat and pressure over millions of years on buried organic matter that originated as dead algal, plankton, and plant remains. Rock units sufficiently rich in organic matter to generate petroleum during burial are called source rocks. After petroleum generation begins, the petroleum is driven from the source rock and migrates along permeable strata and fractures until it is trapped by favourable geological configurations of low-permeability rock or escapes to the surface.

Not all of the petroleum generated in source rocks will migrate; much is left within the source beds themselves. Many of these source rocks are shales and are the targets of many recent unconventional plays.

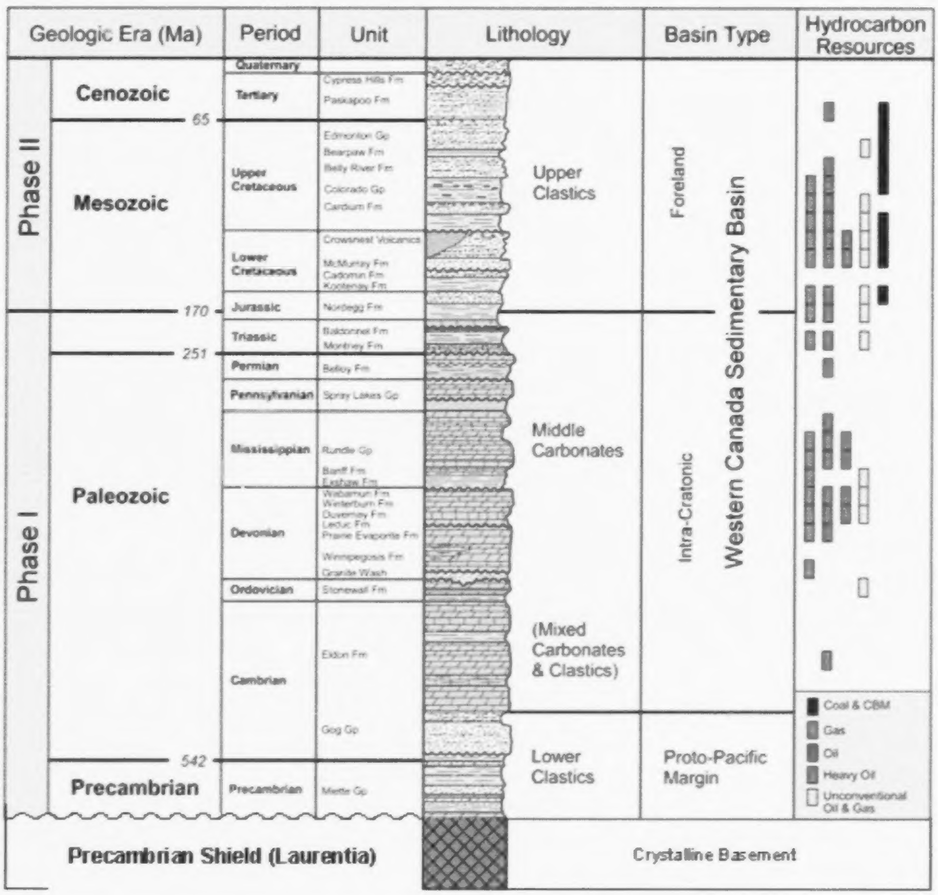
Coal, which is formed by heat and pressure acting on buried plant material, is made of over 50 per cent organic matter and is normally recovered as a commodity for its energy content. However, it can also be a special type of source rock as coalbeds can produce substantial amounts of methane.

The linked assemblage of source rock, migration routes, and ultimate traps is called a petroleum system. The Alberta Basin component of the WCSB contains at least eight petroleum systems associated with the following major source rocks:

- Middle Devonian System – sourced by basinal marine laminites of the Keg River/Winnipegosis formations
- Upper Devonian System – sourced by basinal marine laminites of the Leduc-equivalent Duvernay and Cooking Lake-equivalent Majeau Lake formations
- Upper Devonian System – sourced by basinal laminites of the Cynthia Member of the Nisku Group
- Uppermost Devonian and lowermost Mississippian System – sourced by the basinwide marine mudstones of the Exshaw Formation[4]
- Middle Triassic System – sourced by the marine phosphatic siltstones at the base of the Doig Formation
- Lower Jurassic System – sourced by the marine lime muds of the Nordegg (Gordondale) Member of the Fernie Group
- Lower Cretaceous System – sourced by the continental coals and carbonaceous shales of the Mannville Group

[4] The Exshaw Formation of the Alberta Basin is generally equivalent to the Bakken Formation found within the Williston Basin centered in North Dakota.

Figure 2.3
Generalized stratigraphic column of Alberta



- Upper Cretaceous System – sourced by the marine mudstones of the Colorado Group, principally the First and Second White Speckled Shales and the Fish Scales Zone

The Exshaw, Nordegg, and Duvernay source rocks are thought to have supplied most of the hydrocarbons in the Alberta Basin, and hydrocarbon accumulations within upper systems can be sourced from lower systems. For example, a likely source for the Lower Cretaceous crude bitumen deposits is the Lower Mississippian Exshaw Formation.

Conventional oil and gas pools are found throughout the middle carbonate and upper clastic successions. Little oil and gas is known to occur in the lower clastic succession, and the crystalline basement has none. Coals and coalbed methane (CBM) are found within the Jurassic-, Cretaceous-, and Tertiary-age portions of the upper

clastic succession. Heavy oil pools and crude bitumen[5] deposits occur mostly in Cretaceous-age strata at the shallow updip edge of the Alberta Basin, near the contact of the sedimentary successions with the underlying crystalline rocks of the Precambrian basement. There is also bitumen in the middle carbonate succession directly underneath.

In addition to these accumulations, there is widespread biogenic generation of methane in the shallow subsurface, mostly found in unconsolidated glacial deposits and shallow coal-bearing bedrock units. This gas is pervasive but does not occur in commercial quantities and sometimes is a geological hazard in shallow water wells in Alberta.

2.1.3 Energy Resource Occurrences – Plays, Deposits, and Pools

Estimates of potential volumes of hydrocarbon generation and migration can be quantified for petroleum systems through a detailed basin analysis. Petroleum-system analyses are not generally performed at scales applicable to issues of resource conservation and industry regulation. Instead, each petroleum system can be subdivided into geological plays.

A geological play can be defined as a set of known or postulated oil or gas accumulations (pools and deposits)[6] within a petroleum system sharing similar geological, geographic, and temporal properties, such as source rock, migration pathways, timing, trapping mechanism, and hydrocarbon type. The geographic limit of each play represents the limits of the geological elements that define the play. An example of a geological play in Alberta would be the Pembina Nisku Formation pinnacle-reef sour-gas play.

It is common practice for industry to categorize exploration and development opportunities in terms of geological plays. The AER does not currently designate or otherwise formally declare geological plays. The AER does designate oil sands areas, coal fields, oil and gas pools and fields, and strike areas. These constructs were originally congruous with geological plays, but some have devolved into administrative entities as more geological plays became recognized within and across their boundaries. The AER is considering designating play areas where unconventional resource development is expected to take place.

2.2 Alberta's Endowment of Energy Resources

Alberta has access to a treasure trove of energy resources: coal, bitumen, and conventional and unconventional oil and gas.

2.2.1 Coal, Bitumen, and Conventional Oil and Gas

Coal seams underlie nearly half of Alberta and have been commercially developed for nearly 150 years by several thousand small, and several dozen large, surface and underground mines. Recently, natural gas from

[5] Crude bitumen is extra heavy oil that in its natural state will not flow to a well. Most bitumen in Alberta has been formed by the biodegradation of lighter crude oils.

[6] In general, pools are discrete accumulations of hydrocarbons, whereas deposits are widespread continuous accumulations of hydrocarbons and coal. Pools also can be commingled into larger administrative units.

some of those coal seams, known as coalbed methane or CBM, has begun to be recovered, and the full extent of development potential is still unknown. Other ways of exploiting Alberta's vast coal resources (the largest in Canada), such as through in situ gasification or remote mining, hold out the potential for additional future development.

The AER has conducted numerous assessments of the extent of Alberta's oil sands. Consequently, the AER is confident that there are about two trillion barrels of crude bitumen in-place. It forms one of the largest known petroleum accumulations in the world, ranking it with those in the Middle East, Venezuela, Russia, and the United States. While only a relatively small portion (less than ten per cent) is known to be recoverable with current technology and anticipated economics, it is enough to assure a source of production for many decades into the future. Additionally, should other portions of the oil sands prove commercial, as seems reasonable given the history of worldwide resource extraction, bitumen production could occur for a long period of time.

Conventional oil and gas have been produced for more than 100 years and, after the discovery of oil at Leduc in 1947, have been extensively developed, adding substantial wealth to the province. The WCSB is predominately a gas-prone basin with commercial quantities of natural gas having been found throughout almost the entire province. Oil pools are also widely distributed throughout the province but tend to be in several large clusters. Alberta produces almost three-quarters of Canada's natural gas and almost half of Canada's oil.

As the conventional production of oil and gas continues to decline, "unconventional" recovery methods and the exploitation of "unconventional" reservoirs are on the rise. Reserves and production of crude oil have increased in the last several years, breaking a trend of decades of decline. Natural gas reserves and production continue to decline, but an increasingly higher percentage comes from unconventional sources.

2.2.2 Shale Hydrocarbons

In 2012, the ERCB (the immediate predecessor of the AER) released the report *ERCB/AGS Open File Report 2012-06: Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential*. The report provides baseline data, information, and an understanding of the geology, distribution, reservoir characteristics, and hydrocarbon resource potential of key shale and siltstone units in Alberta.

Initially, the study focused on shale gas in the formations for which industry had shown interest. Later, it was determined that many of the formations analyzed also contained a significant amount of natural gas liquids and oil. Therefore, the study was expanded to include all shale- and siltstone-hosted hydrocarbons.

Hydrocarbons hosted in conventional reservoirs were not included in the evaluation. In cases where conventional, tight (low permeability), and shale resources were present in a rock formation, only the shale- and siltstone-hosted hydrocarbons were evaluated.

In the study, natural gas refers to methane (C_1), natural gas liquids refers to C_2 to C_6 hydrocarbons, and oil refers to C_7 and larger hydrocarbons.

Five units showing immediate potential in Alberta were included in the study: the Duvernay Formation, the Muskwa Formation, the Montney Formation, the Nordegg Member, and the basal Banff and Exshaw formations (sometimes referred to as the Alberta Bakken by industry). Strictly speaking, the Montney Formation is not a "shale" target. In Alberta, the Montney Formation is dominated by siltstone and is included here because it is a target for unconventional resource development. The study also included an assessment of the Wilrich Formation. The assessments of the basal-Banff–Exshaw, north Nordegg, and Wilrich are considered preliminary.

In addition, preliminary work without resource evaluation was done for the Rierdon Formation, the Colorado Group (and equivalent strata of the Smoky and Fort St. John groups), other Fernie Formation units, and the Bantry Shale Member.

The study concluded that shale- and siltstone-hosted hydrocarbon in-place resources are very large and present an important potential energy supply for Alberta and the world. The results demonstrate the size and distribution of shale gas resources in Alberta and may be used to assist in planning resource development and environmental stewardship.

Table 2.1 summarizes the study's estimates of Alberta's shale- and siltstone-hosted hydrocarbon resource endowment for the six investigated units for which available data allowed at least a preliminary determination in billion cubic metres (10^9 m^3). The values represent the medium estimate (having a fifty per cent probability of being the actual volume, and known as the P_{50} estimate) along with the P_{90} to P_{10} (ninety per cent to ten per cent probability) range of resource estimates for natural gas, natural gas liquids, and oil. The P_{50} value is considered to be the best estimate because it minimizes the expected variance from the unknown true value. The range of uncertainty is summarized by the P_{90} (low estimate) and P_{10} (high estimate) values.

The in-place resource estimates in **Table 2.1** should not be confused with recoverable reserves. The recoverable portion of shale hydrocarbon resources is generally determined after drilling and completing a well. Typically, recoverable reserves form a small percentage of unconventional in-place resources, perhaps less than 5 per cent of the resource estimate. If, however, as little as 1 per cent of the total natural gas estimate (3424 Tcf) from **Table 2.1** were to become recoverable by industry through drilling and completion, then Alberta will have added more than 34 Tcf to its reserve endowment. To put this in perspective, Alberta produced 3.5 Tcf of gas during 2013 and had about 33 Tcf of remaining established natural gas reserves at the end of 2013.

Geological and reservoir engineering constraints, recovery factors, and additional economic factors, as well as social and environmental considerations, will ultimately determine the potential recovery of these large resources. See **Section 2.3.3** for additional discussion on the potential recovery of shale hydrocarbons from the Montney Formation.

Maps of the distribution of the P_{50} estimate of hydrocarbon resources in each formation can be found in **Appendix F**. More discussion on Alberta's shale gas resources is given in **Section 5.1.5**.

Table 2.1 Summary of estimates of Alberta shale- and siltstone-hosted hydrocarbon resource endowment[a]

Formation	Average adsorbed gas content (%)	Natural gas (10^9 m^3)	Natural gas liquids (10^6 m^3)	Crude oil (10^6 m^3)
Duvernay	6.8 (5.6–8.5)	12 479 (9 934–15 219)	1 798 (1 190–2 589)	9 803 (7 004–13 172)
Muskwa	6.9 (4.1–10.5)	11 812 (8 132–14 839)	2 350 (949–4 181)	18 296 (11 884–25 412)
Montney	17.7 (10.8–26.0)	60 095 (45 917–79 684)	4 583 (1 852–8 631)	21 653 (12 496–35 035)
Banff/Exshaw[b]	5.7 (3.2–10.0)	993 (446–1 975)	15 (5–35)	3 946 (1 426–7 143)
Nordegg[b]	18.2 (4.6–34.8)	4 164 (1 968–7 905)	228 (77–555)	6 011 (3 161–10 550)
Wilrich[b]	33.7 (6.2–59.2)	6 918 (3 237–16 007)	327 (109–707)	7 611 (3 206–27 380)
Total		**96 461 (3 424 Tcf)[c]**	**9 301 (58.6 10^9 bbls)[d]**	**67 320 (423.6 10^9 bbls)[d]**

[a] The medium estimate (P_{50}) with low (P_{90}) to high (P_{10}) estimates in brackets is shown. Data and interpretations were subjected to geostatistical analysis to provide a probabilistic resource evaluation, indicating P_{10}, P_{50}, and P_{90} confidence results of the initial hydrocarbon in-place.

[b] Estimates based on preliminary data.

[c] Trillion cubic feet.

[d] Barrels.

2.3 Resource Appraisal Methodologies

The AER uses the term "resource appraisal" to encompass all aspects of quantifying Alberta's in-place resources and recoverable reserves. To add clarity to the major components of resource appraisal, this report uses the phrase "resource estimation" to describe activities related to quantifying the amount of energy resources in the ground and the phrase "reserves determination" to describe activities related to quantifying the recoverable portion of these in-place resources (i.e., the established reserves).

2.3.1 Resource Estimation

The AER generates its own resource estimates. The in-place resource estimation process starts with the AER's receipt of raw data from energy resource companies, either as specified by legislation or through regulatory applications or submissions, the vast majority of which is well or borehole data. AER geological staff use pertinent data such as geophysical well logs, cores and drill cuttings, core analysis, and well test data (such as pressure), together with industry or academic information such as reports, seismic data, or regional studies, to estimate petrophysical information and various geological surfaces and zones. These geological and petrophysical evaluations are used for both regulatory and resource appraisal purposes. Several techniques, including geostatistics, are used in generating a volumetric estimate of in-place resources for the various energy resources. As the AER's play catalogue is compiled, resource estimates for each play will be reported.

2.3.2 Reserves Determination

The AER determines two types of estimates of the recoverable portion of Alberta's in-place resources. The portion determined recoverable from known accumulations or deposits using today's technology is classified as "established reserves." The portion determined from known and unknown resources using reasonably foreseeable technology is classified as the "ultimate potential." Established reserves are determined on an ongoing basis, whereas ultimate potentials usually result from major studies conducted periodically. Both terms are estimates of commercial production and are defined in **Section 2.4.**

In determining the established reserves of an energy resource, geology, pressures, production, technology, and present and anticipated economics are all considered. Geological factors are mainly considered when estimating in-place quantities. However, additional considerations are usually required to reduce the in-place quantity to a more likely developable quantity and to assure the existence and extent of the recoverable portion.

Alberta's production of oil and gas has predominantly come from conventional pools in which hydrocarbons have accumulated in concentrated quantities in porous and permeable reservoirs drainable by vertical wells. The AER determines reserves of conventional pools through the accepted practices of geology-based volumetric estimation, production decline analysis, and material balance methodology.

Initially there is a higher level of uncertainty in the reserves estimates, but this level decreases over the life of a pool as more information becomes available and actual production is observed and analyzed. Analysis of production decline data is a primary method of determining recoverable reserves. It also provides a realistic estimation of a pool's recovery efficiency when it is combined with a volumetric or a material balance estimate of the in-place resource.

The determination of reserves in deposits is similar to the methods used to determine pool reserves. One or more factors are applied against an in-place volume or tonnage to determine the recoverable portion of the resource. These reserves are often estimated by three-dimensional geological models that routinely involve the data from hundreds or thousands of wells and drillholes.

2.3.3 Ultimate Potential

Ultimate potential estimates represent recoverable quantities. They are determined for each energy resource commodity over the entire province on the basis of a future end-of-the-day timescale. These estimates are the result of considering all of the development of an energy resource up to the time of the estimate and anticipating cessation of exploration activity and the type of technology that might reasonably be expected to be used in the future.Potential future economic circumstances are also considered. These estimates form a reasonable and credible basis for longer term production forecasts and government policy decisions regarding energy resources. It is presumed that, over time, more and more of the ultimate potential quantities will be transitioned into reserve numbers.

In 2013, the National Energy Board, in conjunction with the B.C. Oil and Gas Commission, the AER, and the B.C. Ministry of Natural Gas Development, released the report *Energy Briefing Note – The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta*. **Table 2.2** shows

Table 2.2 Ultimate potential of the Montney Formation, including the lowermost Doig siltstone, unconventional hydrocarbons in Alberta

	Ultimate in-place			Ultimate potential		
Hydrocarbon type	**Low**	**Expected**	**High**	**Low**	**Expected**	**High**
Natural gas (10^9 m^3)	48 124 (1 699)[a]	65 415 (2 309)[a]	83 474 (2 947)[a]	3 286 (116)[a]	5 042 (178)[a]	7 946 (281)[a]
NGLs (10^6 m^3)	1 910 (12 020)[b]	4 863 (30 599)[b]	8 924 (56 150)[b]	122 (769)[b]	298 (1 874)[b]	584 (3 674)[b]
Oil (10^6 m^3)	12 654 (79 621)[b]	22 045 (138 706)[b]	35 373 (222 569)[b]	71 (444)[b]	174 (1 096)[b]	375 (2 360)[b]

[a] Imperial equivalent in trillion cubic feet.

[b] Imperial equivalent in million barrels.

the Alberta portion of both the in-place resource estimates and the recoverable ultimate potential estimates for natural gas, natural gas liquids, and crude oil for the Montney Formation. The Montney has the largest volumes of hydrocarbons of the six stratigraphic units listed in **Table 2.1**. The slightly higher in-place values shown in **Table 2.2**, when compared to **Table 2.1**, are due to the inclusion, in Alberta, of the lowermost Doig siltstone (making the unit equivalent to the Upper Montney Formation in British Columbia).

Should the estimated ultimate potential of marketable natural gas shown in **Table 2.2** actually be recovered, it would mark a five-fold increase in Alberta's remaining gas reserves. The potential recoverable natural gas liquids and crude oil would represent a 118 per cent and a 65 per cent increase respectively in Alberta's remaining reserves.

2.4 Resources and Reserves Classification System

The AER reports the reserves of Alberta by commodity (crude bitumen, crude oil, natural gas, natural gas liquids, sulphur,[7] and coal) based on the Inter-Provincial Advisory Committee on Energy (IPACE) system for uniform terminology and definitions in estimating and publishing hydrocarbon reserves information in Canada. The IPACE system was adopted by most government and national bodies for reserves reporting in Canada in 1978 and has been in use since that time. The IPACE system was designed as a simple categorization of reserves to facilitate understanding and transparency in reporting to the public. The key definitions in the IPACE system are as follows:

- Initial volume in-place – the gross volume of crude oil, crude bitumen, or raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced.
- Established reserves – those reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing, or production, plus that judgement portion of contiguous recoverable reserves that are interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.

[7] Sulphur reserves are included because they are a direct by-product of sour natural gas development, as well as that portion of raw crude bitumen that is upgraded.

- Initial established reserves – established reserves prior to the deduction of any production.
- Remaining established reserves – initial established reserves less cumulative production.
- Ultimate potential – an estimate of the initial established reserves that will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools.

The IPACE system was designed, and is most appropriate, for use with conventional oil and gas resources. Consequently, the AER has introduced changes to the IPACE system to make it compatible for all energy resources, including coal. More recently, alterations have also been applied to unconventional resources, such as crude bitumen, to more completely report the resource endowment of Alberta.

Since 1978, and particularly since 1997, the mineral and petroleum industries have strived for tighter definitions of reserves to better suit financial markets. In Canada, these efforts include the promulgation of *National Instrument (NI) 43-101: Standards of Disclosure for Mineral Projects*[8] in 2000 for Canadian minerals (including coal) securities reporting, the promulgation of *NI 51-101: Standards of Disclosure for Oil and Gas Activities* in 2003 for petroleum reserve reporting to Canadian securities regulators, and the creation of and updates to the *Canadian Oil and Gas Evaluation Handbook* (*COGEH*).[9] International standards include the *International Template for Reporting of Exploration Results, Mineral Resources and Mineral Reserves* in 2003, the *Petroleum Resources Management System* (*PRMS*)[10] in 2007, and the *United Nations Framework Classification for Fossil Energy and Mineral Reserves and Resources 2009* (*UNFC-2009*).[11] The AER is reviewing these efforts and will decide to either maintain or modify the IPACE system or to adopt one or more of these newer frameworks in the future.

[8] The technical basis of *NI 43-101* is the *Definition Standards on Mineral Resources and Mineral Reserves* prepared by the Canadian Institute of Mining, Metallurgy and Petroleum. This standard is based on other international standards that have now been consolidated into the template, which was prepared by the Committee for Mineral Reserves International Reporting Standards.

[9] The *COGEH*, first published in 2002, was prepared by the Calgary Chapter of the Society of Petroleum Evaluation Engineers and the then Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum (now part of the Society of Petroleum Engineers). *COGEH* forms the technical basis of *NI 51-101*.

[10] The *PRMS* was prepared by the Society of Petroleum Engineers and reviewed and jointly sponsored by the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers.

[11] The first edition of *UNFC-2009* was published in 2004.

HIGHLIGHTS

Total bitumen production increased by 8 per cent, mineable production increased by 5 per cent, and in situ production increased by 12 per cent.

Upgraded bitumen production increased by 2 per cent.

3 CRUDE BITUMEN

Crude bitumen is extra heavy oil that in its natural state does not flow to a well. It occurs in sand (clastic) and carbonate formations in northern Alberta. Crude bitumen and the rock material it is found in, together with any other associated mineral substances other than natural gas, are called oil sands. For administrative purposes, the geological formations and the geographic areas containing the bitumen are designated as oil sands areas (OSAs). Other heavy oil is deemed to be oil sands if it is located within an OSA. Since some bitumen within an OSA will flow to a well, it is amenable to primary development and is considered to be primary crude bitumen in this report.

The three designated OSAs in Alberta are shown in **Figure R3.1**. Combined, they occupy an area of about 142 000 square kilometres (km^2) (54 000 square miles). Contained within the OSAs are 15 oil sands deposits designated according to the specific geological zones containing the oil sands. The known extent of the two largest deposits, the Athabasca Wabiskaw-McMurray and the Athabasca Grosmont, as well as the Cold Lake Clearwater and Peace River Bluesky-Gething deposits, are also shown in the figure. As an indication of scale, the right-hand edge shows township markers that are about 50 km (30 miles) apart.

Depending on the depth of the deposit, one of two methods is used to recover bitumen. North of Fort McMurray, crude bitumen occurs near the surface and can be recovered economically by open-pit mining. In this method, overburden is removed, oil sands ore is mined, and bitumen is extracted from the mined material in large facilities using hot water. At greater depths, where it is not economical to recover the bitumen by mining, in situ methods are employed. In situ recovery takes place both by primary development, similar to conventional crude oil production, and by enhanced development. Cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD) are the two main methods of enhanced development whereby the reservoir is heated to reduce the viscosity of the bitumen, allowing it to flow to a vertical or horizontal wellbore.

3.1 Reserves of Crude Bitumen

3.1.1 Provincial Summary

The AER continually updates Alberta's crude bitumen resources and reserves on both a project and deposit basis. The remaining established reserves as of December 31, 2013, are 26.56 billion cubic metres (10^9 m^3). This is a slight reduction from the previous year due to 0.13 10^9 m^3 of production. Of the total

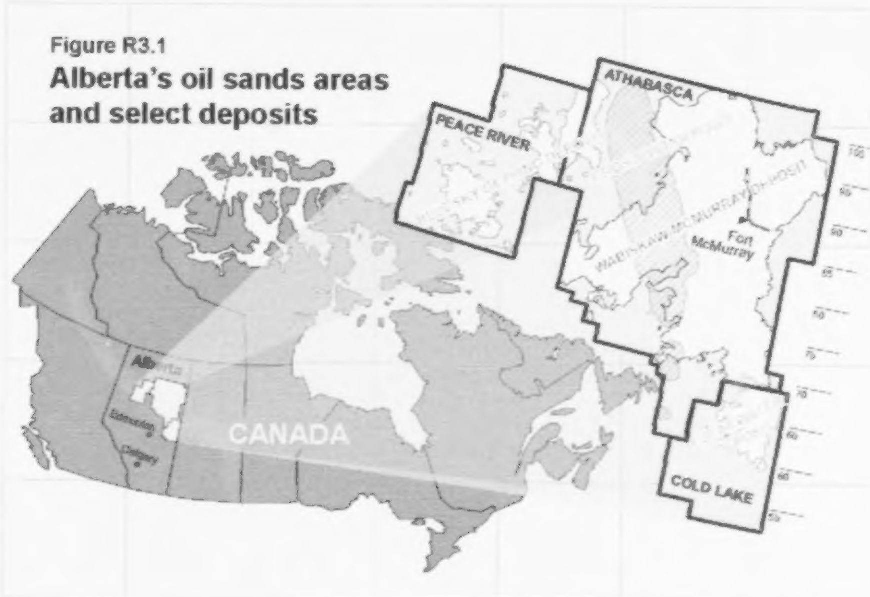


Figure R3.1
Alberta's oil sands areas and select deposits

26.56 10^9 m^3 remaining established reserves, 21.34 10^9 m^3, or about 80 per cent, is considered recoverable by in situ methods, while the remaining 5.22 10^9 m^3 is recoverable by surface mining methods. Of the in situ and mineable totals, the remaining established reserves within active development areas is 4.01 10^9 m^3. **Table R3.1** summarizes the in-place and established mineable and in situ crude bitumen reserves.

The changes, in million cubic metres (10^6 m^3), in initial and remaining established crude bitumen reserves and cumulative and annual production for 2013 are shown in **Table R3.2**. Crude bitumen production in 2013 totalled 121 10^6 m^3, with in situ operations contributing 64 10^6 m^3.

The remaining established reserves in active development areas are presented in **Figure R3.2**. These project reserves have a staircase configuration representing start-up of new large mining projects. The intervening years between additions are characterized by a slow decline due to annual production.

3.1.2 Initial In-Place Volumes of Crude Bitumen

Efforts to update the province's crude bitumen resources and reserves began in 2003, and since then 11 of the 15 deposits have been updated. The Athabasca Wabiskaw-McMurray deposit, with the largest cumulative and annual production, was updated for year-end 2004 and subsequently revised in 2009 to take new drilling into account. The Cold Lake Clearwater deposit has the second largest production and was updated for year-end 2005. The northern portion of the Cold Lake Wabiskaw-McMurray deposit was also updated for year-end 2005. The Peace River Bluesky-Gething deposit was updated for year-end 2006.

In 2009, the AER completed a major review of the Cold Lake Upper and Lower Grand Rapids deposits and the Athabasca Grosmont deposit. The Athabasca Upper, Middle, and Lower Grand Rapids deposits and the Athabasca Nisku deposit were reassessed for year-end 2011. Bitumen pay thickness maps for these deposits are

Table R3.1 In-place volumes and established reserves of crude bitumen (10^9 m^3)

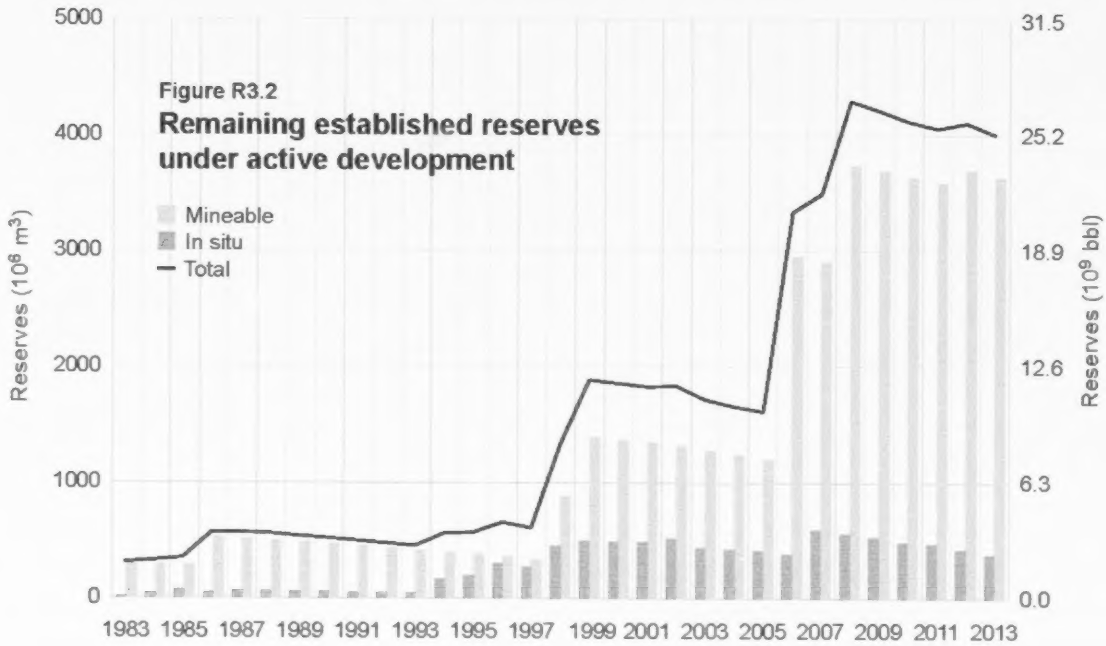
Recovery method	Initial volume in-place	Initial established reserves	Cumulative production	Remaining established reserves	Remaining established reserves under active development
Mineable	20.8	6.16	0.93	5.22	3.63
In situ	272.3	21.94	0.60	21.34	0.38
Total	**293.1** (1 845 10^9 bbl)[b]	**28.09**[a] (176.8 10^9 bbl)[b]	**1.53** (9.6 10^9 bbl)[b]	**26.56**[a] (167.1 10^9 bbl)[b]	**4.01** (25.3 bbl)[b]

[a] Any discrepancies are due to rounding.
[b] bbl = barrels.

Table R3.2 Reserve and production change highlights (10^6 m^3)

	2013	2012	Change[a]
Initial established reserves			
Mineable	6 157	6 157	0
In situ	21 935	21 935	0
Total[a]	**28 092**	**28 092**	**0**
	(176 780 10^6 bbl)[b]	(176 780 10^6 bbl)[b]	
Cumulative production			
Mineable	931	874	+57[c]
In situ	596	532	+64[c]
Total[a]	**1 527**	**1 406**	**+121**[c]
Remaining established reserves			
Mineable	5 226	5 283	-57
In situ	21 339	21 403	-64
Total[a]	**26 565**	**26 686**	**-121**
	(167 171 10^6 bbl)[b]	(167 932 10^6 bbl)[b]	
Annual production			
Mineable	57	54	+3
In situ	64	58	+6
Total[a]	**121**	**112**	**+9**

[a] Any discrepancies are due to rounding.
[b] bbl = barrels.
[c] Change in cumulative production is a combination of annual production and all adjustments to previous production records.



presented in **Appendix E**. Also included in **Appendix E** are two structure contour maps of the sub-Cretaceous unconformity. One is a regional map covering all the OSAs, the other is a map detailing the Cold Lake OSA.

Recently, industry has been actively exploring the Leduc Formation for potential bitumen resources west of Fort McMurray. Preliminary results indicate that bitumen pay thickness may exceed 100 m.

The quality of an oil sands deposit depends primarily on the degree of saturation of bitumen within the reservoir and the thickness of the saturated interval. Bitumen saturation decreases as the shale or clay content within the reservoir increases or as the porosity decreases. The relative amount of bitumen is expressed as mass per cent in clastics (the percentage of bitumen relative to the total mass of the oil sands, which includes sand, shale or clay, bitumen, and water). In carbonates, the relative amount of bitumen is expressed as bitumen saturation (the percentage of the volume of pore space that contains bitumen). The selection of appropriate saturation and thickness cutoffs for determining resources and reserves varies depending on the purpose of the resource evaluation and other factors, such as changes in technology and economic conditions.

Initial in-place volumes of crude bitumen in each deposit were determined using geophysical logs, core, and core analyses. Initially, crude bitumen within the Cretaceous sands was evaluated using a minimum saturation cutoff of 3 mass per cent crude bitumen and a minimum saturated zone thickness of 1.5 m for in situ areas. As of year-end 1999, the saturation cutoff was increased to 6 mass per cent for areas amenable to surface mining. The Athabasca Wabiskaw-McMurray; Athabasca Upper, Middle, and Lower Grand Rapids; Cold Lake Clearwater; Cold Lake Upper and Lower Grand Rapids; and the Peace River Bluesky-Gething deposits, as well as a portion of the Cold Lake Wabiskaw-McMurray deposit, were estimated using a 6 mass per cent saturation cutoff.

The crude bitumen within the carbonate deposits was originally determined using a minimum bitumen saturation of 30 per cent of pore volume and a minimum porosity value of 5 per cent. In the revision of the Athabasca Grosmont and Nisku deposits, a pore volume of 50 per cent and a porosity of 8 per cent were chosen as more appropriate cutoff values.

The AER believes that in measuring the quality of an oil sands area, cutoffs of 6 mass per cent for clastic bitumen deposits and a pore volume of 50 per cent and a porosity of 8 per cent for carbonate bitumen deposits more accurately reflect the volumes from which bitumen can reasonably be expected to be recovered.

Within the Athabasca OSA is the AER-defined surface mineable area (SMA). It encompasses an area of 51½ townships north of Fort McMurray, covering the part of the Athabasca Wabiskaw-McMurray deposit where the total overburden thickness generally does not exceed 65 m. Given the thinner overburden, it is presumed that the main recovery method will be surface mining. Outside of the SMA, in the designated OSAs, in situ technology is the only viable recovery mechanism to date.

The defined boundaries of the SMA are simply for resource administration purposes and carry no regulatory authority. While the AER has estimated mineable reserves from unmined areas within the SMA for provincial resource assessment purposes, surface mining may not actually take place, possibly reducing the estimate of mineable reserves. Within the SMA, just under 50 per cent of the initial mineable bitumen in-place resources occurs at a depth of less than 25 m of overburden. Since the boundaries of the SMA are defined using the boundaries of townships, a few areas of deeper bitumen resources more amenable to in situ recovery are included (i.e., the extent of the SMA covers both mineable and in situ resources). Estimates of mineable bitumen exclude those volumes within the SMA that are beyond mineable depths. Conversely, in situ estimates include all areas outside the SMA, as well as deeper areas within the SMA, which are generally greater than 65 m.

The crude bitumen resource volumes and basic reservoir data are presented on a deposit basis in **Appendix B (Table B.1** and **Table B.2)** and are summarized by formation in **Table R3.3**.

The in-place resource values in **Table R3.3** represent the total crude bitumen accumulated throughout the deposit where the cumulative thickness is equal to or greater than 1.5 m; however, current and anticipated recovery operations often only develop the better quality portion of this total. This developable portion (also known as mineable and exploitable) varies depending on the type of recovery technology employed. Recovery factors are normally applied against this developable portion to determine the established reserves. The parameters used to reduce the total in-place volumes to a developable subset are given in **Section 3.1.3**.

3.1.3 Established Reserves

There are two types of established reserves of crude bitumen: mineable reserves that are anticipated to be recovered by surface mining operations and in situ reserves that are anticipated to be recovered through wellbores using in situ recovery methods.

Table R3.3 Initial in-place volumes of crude bitumen as of December 31, 2013

Oil sands area Oil sands deposit	Initial volume in-place (10^6 m^3)	Area (10^3 ha)[a]	Average pay thickness (m)	Average reservoir parameters Mass (%)	Pore volume oil (%)	Average porosity (%)
Athabasca						
Upper Grand Rapids	5 817	359	8.5	9.2	58	33
Middle Grand Rapids	2 171	183	6.8	8.4	55	32
Lower Grand Rapids	1 286	134	5.6	8.3	52	33
Wabiskaw-McMurray (mineable)	20 823	375	25.9	10.1	76	28
Wabiskaw-McMurray (in situ)	131 609	4 694	13.1	10.2	73	29
Nisku	16 232	819	14.4	5.7	68	20
Grosmont	64 537	1 766	23.8	6.6	79	20
Subtotal	**242 475**					
Cold Lake						
Upper Grand Rapids	5 377	612	4.8	9.0	65	28
Lower Grand Rapids	10 004	658	7.8	9.2	65	30
Clearwater	9 422	433	11.8	8.9	59	31
Wabiskaw-McMurray	4 287	485	5.1	8.1	62	28
Subtotal	**29 090**					
Peace River						
Bluesky-Gething	10 968	1 016	6.1	8.1	68	26
Belloy	282	26	8.0	7.8	64	27
Debolt	7 800	258	25.3	5.1	66	18
Shunda	2 510	143	14.0	5.3	52	23
Subtotal	**21 560**					
Total	**293 125**					

[a] ha = hectare.

3.1.3.1 Surface-Mineable Crude Bitumen Reserves

With the 2008 expansion of the SMA and the subsequent updating of the Athabasca Wabiskaw-McMurray deposit (the only oil sands deposit in the SMA), the AER now estimates that the SMA contains 20.8 10^9 m^3 of initial bitumen in-place resources at depths most suitable to mining technologies, generally less than 65 m. For year-end 2008, economic criteria were applied to potentially mineable areas in the total in-place portion of the SMA. Economic strip ratio (ESR) criteria, along with a minimum saturation cutoff of 7 mass per cent bitumen and a minimum saturated interval thickness cutoff of 3.0 m, were applied. The ESR criteria are fully explained in Appendix III of *ERCB Report 79-H: Alsands Fort McMurray Project*. This method reduced the total initial mineable bitumen in-place resources of 20.8 10^9 m^3 to 10.3 10^9 m^3 as of December 31, 2008.

Factors were then applied to the initial mineable volume in-place to determine the established reserves. A series of reduction factors were applied to take into account bitumen ore sterilized due to environmental protection corridors along major rivers, small isolated ore bodies, and the location of surface facilities (plant sites, tailings ponds, and waste dumps). Each of these reductions is thought to represent about 10 per cent of the total volume; therefore, each factor is set at 90 per cent. A combined mining and extraction recovery factor of 82 per cent is applied to this reduced resource volume. This recovery factor reflects the combined loss, on average, of 18 per cent of the in-place volume by mining operations and extraction facilities. The resulting initial established reserves of crude bitumen is 6.16 10^9 m^3. As of December 31, 2013, the remaining established mineable crude bitumen reserves has decreased from 5.28 10^9 m^3 year-end 2012 to 5.22 10^9 m^3 as a result of production.

The remaining established crude bitumen reserves from deposits under active development as of December 31, 2013, are presented in **Table R3.4**. At the end of 2013, almost three quarters of the initial established reserves were under active development. Currently, Canadian Natural Resources Limited (CNRL Horizon), Shell Canada Energy Limited (Shell Muskeg River and Shell Jackpine), Imperial (Kearl), Suncor Energy Inc. (Suncor), and Syncrude Canada Ltd. (Syncrude) are the only producers in the SMA, with a combined cumulative bitumen production of 931 10^6 m^3. The Fort Hills project (owned by Suncor, Total E&P Canada Ltd. [Total], and Teck Resources Ltd. [Teck]) is not yet producing bitumen but is considered to be under active development and is included in **Table R3.4**. Total's Joslyn North mine project was added to **Table R3.4** for 2013 as it was approved in 2010 and activity has begun at the site. The AER has adjusted the initial mineable volume in-place and the initial established reserves for the Fort Hills mine based on recent drilling information and changes to the project area. In 2013, a hearing on the Shell Jackpine Expansion Mine project was held before a joint AER/federal panel and the project was approved in December 2013. The project reserve estimates are not yet available for inclusion into **Table R3.4**. Mine project applications currently under review are Shell Pierre River and Teck Frontier.

Table R3.4 Mineable crude bitumen reserves in areas under active development as of December 31, 2013

Development	Project area[a] (ha)	Initial mineable volume in-place (10^6 m^3)	Initial established reserves (10^6 m^3)	Cumulative production (10^6 m^3)	Remaining established reserves (10^6 m^3)
CNRL Horizon	28 482	834	537	26	511
Fort Hills	17 864	556	382	0	382
Imperial Kearl	19 674	1 324	872	1.4	871
Shell Muskeg River	13 581	672	419	86	333
Shell Jackpine	7 958	361	222	18	204
Suncor	19 155	990	687	331	356
Syncrude	44 037	2 071	1 306	468	838
Total Joslyn North	8 604	274	139	0	139
Total	**159 355**	**7 100**	**4 564**	**930**	**3 634**

[a] The project areas correspond to the areas defined in the project approval.

Production from the six current surface mining operations amounted to 56.64 10^6 m^3 in 2013, with 18.95 10^6 m^3 from the Syncrude project, 15.65 10^6 m^3 from the Suncor project, 7.94 10^6 m^3 from the Shell Muskeg River project, 5.85 10^6 m^3 from the Shell Jackpine project, 6.80 10^6 m^3 from the CNRL Horizon project, and 1.45 10^6 m^3 from the Imperial/Exxon Kearl project.

3.1.3.2 In Situ Crude Bitumen Reserves

The AER has determined in situ initial established reserves for those areas considered suitable for in situ recovery methods. Reserves are estimated using cutoffs appropriate to the type of development and differences in reservoir characteristics. For each oil sands deposit with commercial development, the areas with potential for thermal development were determined using a minimum continuous zone thickness of 10.0 m. For deposits with primary development, a minimum continuous zone thickness of 3.0 m (or lower if currently being recovered at a lesser thickness) was used. While some reserve estimates have been updated using a minimum saturation cutoff of 6 mass per cent bitumen, much of the current data is still based on the 3 mass per cent bitumen cutoff for most deposits. Future reserve estimates will be based on values higher than 3 mass per cent.

Recovery factors of 20 per cent for thermal development and 5 per cent for primary development were applied to areas that met the cutoffs. The deposit-wide recovery factor for thermal development is lower than some of the recovery factors for projects under active development to account for the uncertainty in the recovery processes and the uncertainty of development in the poorer quality resource areas.

The volume of the in-place crude bitumen was reassessed in the Athabasca Grosmont deposit in 2009 and the Athabasca Nisku and Upper, Middle, and Lower Grand Rapids deposits in 2011. No reserves were estimated as no commercial projects are currently operating within these deposits. Exploration has occurred and different recovery methods have been experimented with, but commercial operations have yet to be established. The AER estimates reserves only in deposits where commercial operations are in place.

In 2013, the in situ bitumen produced was 64.40 10^6 m^3, an increase from 57.72 10^6 m^3 in 2012. Cumulative production within in situ areas now totals 596.7 10^6 m^3, of which 366.6 10^6 m^3 is from the Cold Lake OSA. The remaining established reserves of crude bitumen from in situ areas decreased from 21.40 10^9 m^3 in 2012 to 21.34 10^9 m^3 in 2013 due to production of 0.06 10^9 m^3.

The AER's 2013 estimate of the established in situ crude bitumen reserves under active development is shown in **Table R3.5**. In the Peace River OSA, for 2013, the estimates of crude bitumen for primary schemes was reassessed due to an increase in active development area, resulting in a doubling of the initial volume in-place and initial established reserves. The remaining established reserves for Peace River primary schemes has increased from 1.3 10^6 m^3 in 2012 to 19.9 10^6 m^3 in 2013. Information on experimental schemes has been removed from the table due to the limited number of experimental schemes and the confidential nature of the associated production data.

The AER has assigned initial volumes in-place and initial and remaining established reserves for commercial projects and primary recovery schemes where all or a portion of the wells have been drilled and completed. An

aggregate reserve is also shown for all commercial projects and primary recovery schemes within a given oil sands deposit and area. Initial established reserves under primary development are based on a 5 per cent average recovery factor. In Peace River, however, a 10 per cent recovery factor, based on production, is used. Primary schemes in Athabasca undergoing enhanced recovery by polymer injection or waterflooding have an additional 10 per cent recovery factor applied. The application of various steaming strategies and project designs are reflected in the recovery factors of 40, 50, and 25 per cent for thermal commercial projects in the Peace River, Athabasca, and Cold Lake OSAs, respectively.

The remaining established reserves of crude bitumen within active in situ project areas are estimated to be 375.4 10^6 m^3, a decrease from 2012's 418.6 10^6 m^3 due to production.

Table R3.5 In situ crude bitumen reserves in areas under active development as of December 31, 2013[a]

Development	Initial volume in-place (10^6 m^3)	Recovery factor (%)	Initial established reserves (10^6 m^3)	Cumulative production[b] (10^6 m^3)	Remaining established reserves (10^6 m^3)
Peace River Oil Sands Area					
Thermal commercial projects	63.7	40	25.5	11.8	13.7
Primary recovery schemes	375.0	10	37.5	17.6	19.9
Subtotal[c]	**438.7**		**63.0**	**29.4**	**33.6**
Athabasca Oil Sands Area					
Thermal commercial projects	391.8	50	195.9	149.2	46.7
Primary recovery schemes	1 026.2	5	51.3	25.4	25.9
Enhanced recovery schemes[d]	(289.0)[e]	10	28.9	26.1	2.8
Subtotal[c]	**1 418.0**		**276.1**	**200.7**	**75.4**
Cold Lake Oil Sands Area					
Thermal commercial (CSS)[f]	1 212.8	25	303.2	256.0	47.2
Thermal commercial (SAGD)[g]	33.8	50	16.9	4.6	12.3
Primary recovery schemes	6 257.5	5	312.9	106.0	206.9
Subtotal[c]	**7 504.1**		**633.0**	**366.6**	**266.4**
Total[c]	**9 360.8**		**972.1**	**596.7**	**375.4**

[a] Thermal reserves are reported only for lands on which thermal recovery is approved and drilling development has occurred.
[b] Includes amendments to production reports.
[c] Any discrepancies are due to rounding.
[d] Schemes currently on polymer injection or waterflooding in the Brintnell-Pelican area. Previous primary production is included under primary recovery schemes.
[e] The in-place number is that part of the initial volume available for primary recovery schemes that will see incremental production due to polymer injection or waterflooding.
[f] Cyclic steam stimulation projects.
[g] Steam-assisted gravity drainage projects.

3.1.4 Ultimate Potential of Crude Bitumen

The ultimate potential of crude bitumen recoverable by in situ methods is estimated to be 33 10^9 m^3 from Cretaceous clastic sediments and 6 10^9 m^3 from Paleozoic carbonate sediments. Nearly 11 10^9 m^3 of bitumen was expected to be recovered within the original boundaries of the SMA. The ultimate potential from within the area of expansion has yet to be estimated, leaving the total ultimate potential for crude bitumen unchanged at 50 10^9 m^3.

3.2 Supply of and Demand for Crude Bitumen

This section includes crude bitumen production, upgrading, and disposition of both upgraded and nonupgraded bitumen. Nonupgraded bitumen refers to crude bitumen that is blended with a lighter-viscosity product (referred to as a diluent) to meet specifications for transport through pipelines. Upgraded bitumen refers to the portion of crude bitumen production that is upgraded to synthetic crude oil or other petroleum products. Most upgraded bitumen is used by refineries as feedstock.

Upgraders[1] chemically alter the bitumen by adding hydrogen, removing carbon, or both. In upgrading, the sulphur contained in bitumen may be removed, either in elemental form or as a constituent of oil sands coke. The bitumen upgrading process produces off-gas that is high in natural gas liquids (NGLs) and olefins. The off-gas has primarily been used as fuel in oil sands operations; however, there are increasing volumes of off-gas being processed to remove the NGLs and olefins, which are used as feedstock in the petrochemical industry. Most oil sands coke recovered as a by-product of the upgrading process is stockpiled, while small amounts are burned to generate electricity or are sold to market. Elemental sulphur is either stockpiled or shipped to facilities that convert it to sulphuric acid, which is mainly used to manufacture fertilizers.

Condensates[2] and upgraded bitumen are two main types of diluent used to lower the viscosity of bitumen for transport in pipelines, although naphtha, light crude oil, and butanes can also be used to enable the bitumen to meet pipeline specifications. Condensates are lighter than upgraded bitumen as a diluent, which means a smaller volume of condensates is required to move bitumen through a pipeline. On average, a blend of bitumen and condensates will contain 30 per cent condensates, whereas a blend using upgraded bitumen will contain up to 50 per cent upgraded bitumen to meet pipeline specifications.

If condensates are used as a diluent to transport bitumen to destinations within Alberta, they are usually recycled. However, if they are used to transport bitumen to markets outside Alberta, they are generally not returned to the province. Instead, the condensates are used as part of the feedstock for upgraders and refineries downstream. As demand for condensates has grown, there has been an increasing number of projects aimed at delivering condensates to the province. In 2012, Kinder Morgan announced plans to partially reverse the flow of the western

[1] An upgrader refers to an oil sands processing plant that upgrades bitumen into lighter hydrocarbon products. The AER regulates upgraders as processing plants under the *Oil Sands Conservation Act* and as oil sands processing plants under the *Environmental Protection and Enhancement Act*.

[2] The term "condensates," as used in this section, applies to Alberta production of condensates and pentanes plus in addition to imported volumes of condensate.

portion of the Cochin pipeline system to deliver condensate to Alberta. Further, in 2013 Enbridge announced plans to expand the Southern Lights pipeline, which initially began delivering additional imported diluent from the U.S. Petroleum Administration Defense District (PADD) 2 to Alberta in 2010. The Plains Rainbow II pipeline is also being proposed to transport condensate and butane and will closely mirror the route of the original Rainbow pipeline.

The forecast of crude bitumen and upgraded bitumen production relies heavily on information provided by project proponents. This includes data on production capacity submitted during a project's application process, in addition to other publicly available materials, such as quarterly reports, presentations, and press releases, which provide information on schedules for bringing the resource on stream. A project's viability depends largely on the cost-price relationship between production, operating and transportation costs (supply), and the market price for bitumen and upgraded bitumen (demand). Other factors include the refining capacity to handle bitumen or upgraded bitumen and competition with other sources of supply in U.S. and Canadian markets. The forecasts for crude bitumen and upgraded bitumen include production from existing projects, expansions of existing projects, and new projects that have been granted or are currently seeking approval. Demand for upgraded bitumen and nonupgraded bitumen in Alberta is based on refinery demand and transportation needs. Alberta upgraded and nonupgraded bitumen supply in excess of Alberta demand is marketed outside the province.

Project sponsors' projections of existing and future bitumen production can change over time for various reasons. Large oil sands production projects are complex and capital intensive. They require long lead and construction times, making the projects vulnerable to material and labour cost increases throughout the planning, construction, and production phases.

3.2.1 Crude Bitumen Production – 2013

Surface mining and in situ production for 2013 are shown graphically by oil sands area (OSA) in **Figure S3.1**. In 2013, Alberta produced an average 331.4 thousand (10^3) m^3/d of crude bitumen from all three OSAs, compared with 305.5 10^3 m^3/d in 2012. Of this 25.9 10^3 m^3/d increase in production, 18.5 10^3 m^3/d was from in situ schemes and 7.4 10^3 m^3/d was from mining. Regionally, in situ production growth was strongest in Athabasca (19.0 per cent increase) followed by Peace River (6.3 per cent increase) then Cold Lake (2.4 per cent increase). Combined, production for all three in situ areas grew by 11.7 per cent, compared with 5.0 per cent growth for mined bitumen production.

Overall, the increase in crude bitumen production of 25.9 10^3 m^3/d represents an annual increase of 8.5 per cent, which is slightly lower than the production increase of 10.2 per cent between 2011 and 2012. Production from in situ projects continued to exceed mined production in 2013 and is expected to continue to do so going forward. In 2013, in situ production accounted for 53 per cent of total bitumen production, compared with 52 per cent in 2012. **Figure S3.2** shows combined upgraded bitumen and nonupgraded bitumen production as a percentage of Alberta's total crude oil and equivalent production. The combined volume of upgraded bitumen and nonupgraded bitumen has increased from 48 per cent of the province's total crude oil production in 2002 to 73 per cent in 2013.

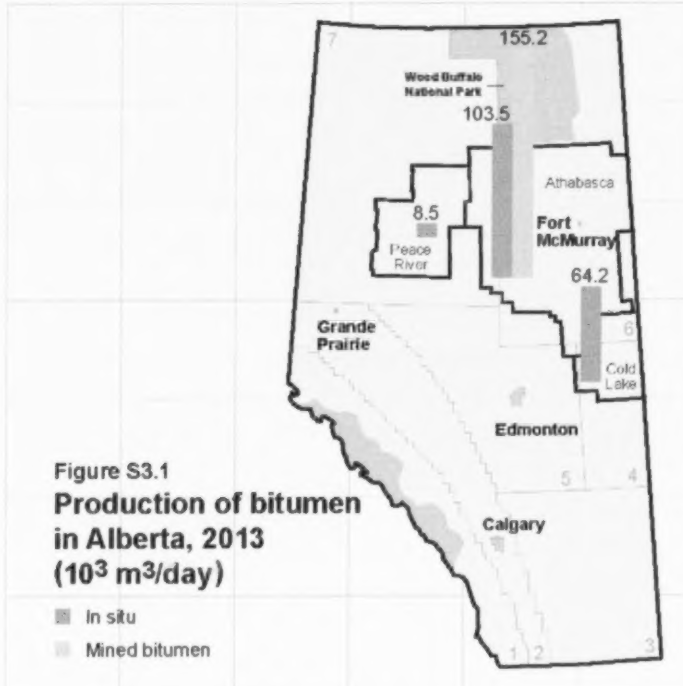


Figure S3.1
Production of bitumen in Alberta, 2013 (10^3 m³/day)

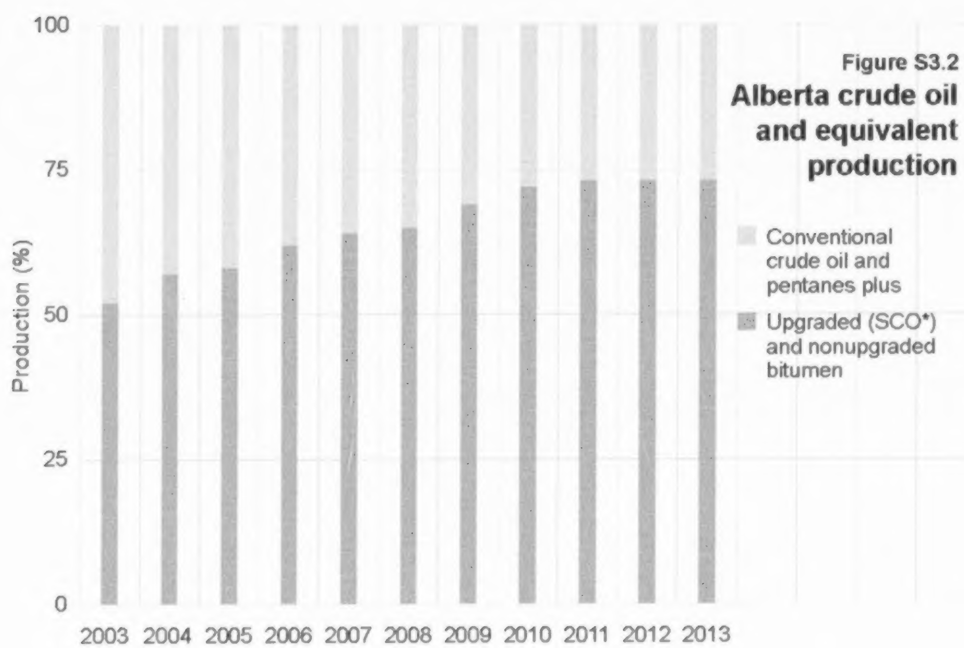


Figure S3.2
Alberta crude oil and equivalent production

*Synthetic crude oil.

3.2.1.1 Mined Crude Bitumen

Annual mined production growth was 7.4 10^3 m^3/d in 2013 as daily volumes grew to an average 155.2 10^3 m^3/d, up from 147.8 10^3 m^3/d in 2012. Production growth in 2013 at 5.0 per cent was slightly higher than growth in 2012 at 4.2 per cent. Growth in production was driven by gains at Shell and CNRL of 2.0 10^3 m^3/d and 2.3 10^3 m^3/d, respectively, and the start-up of Imperial's Kearl project, which reported first production in April 2013.

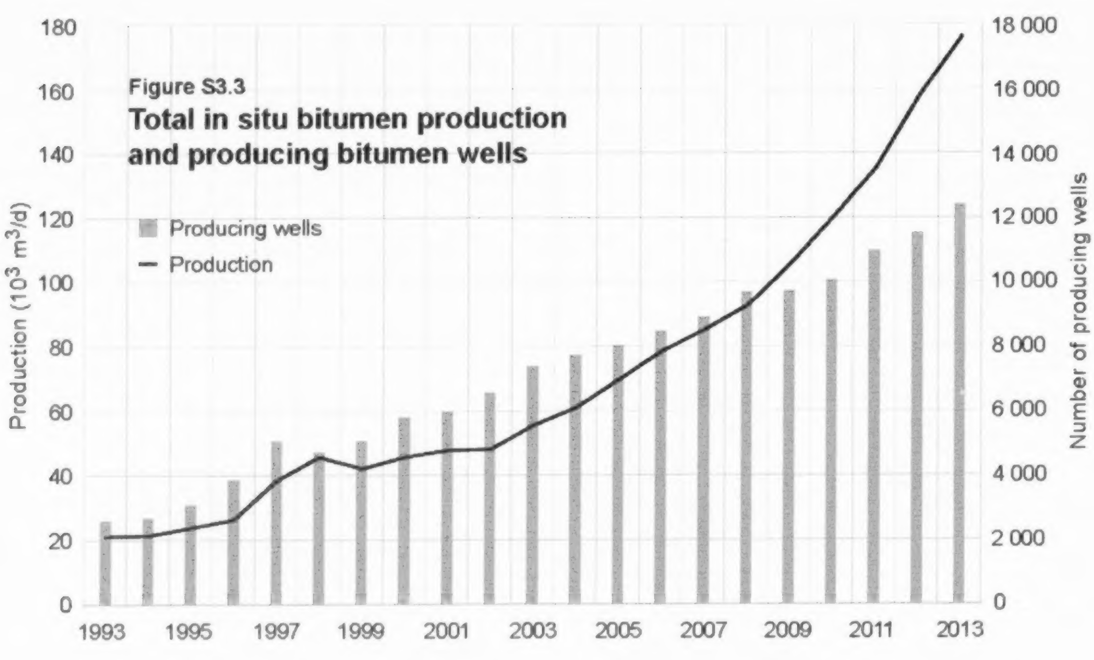
Syncrude (Mildred Lake and Aurora), Suncor (all mining operations), Shell (Muskeg River and Jackpine), CNRL (Horizon), and Imperial (Kearl) account for 33, 28, 24, 12, and 3 per cent of total mined bitumen, respectively.

Syncrude's mined bitumen production in 2013 decreased by 2.6 per cent since 2012 and averaged 51.9 10^3 m^3/d. Production of mined bitumen at Suncor averaged 42.8 10^3 m^3/d, up 1.3 per cent since 2012. Shell's Muskeg River and Jackpine mining projects combined produced 37.8 10^3 m^3/d in 2013, a 5.5 per cent increase over 2012. CNRL's Horizon project produced 18.6 10^3 m^3/d in 2013, an increase of 13.9 per cent since 2012, reflecting increased on-stream time at the upgrader.

3.2.1.2 In Situ Crude Bitumen

In situ crude bitumen production for 2013 increased to an average 176.2 10^3 m^3/d from 157.7 10^3 m^3/d in 2012. This represents an 11.7 per cent increase, consistent with the average growth rate of 12.6 per cent seen between 2003 and 2012, but lower than the increase of 16.5 per cent from 2011 to 2012.

Annual total in situ bitumen production, along with the number of bitumen wells on production for each year, is shown in **Figure S3.3**. The number of producing bitumen wells has increased along with in situ crude bitumen

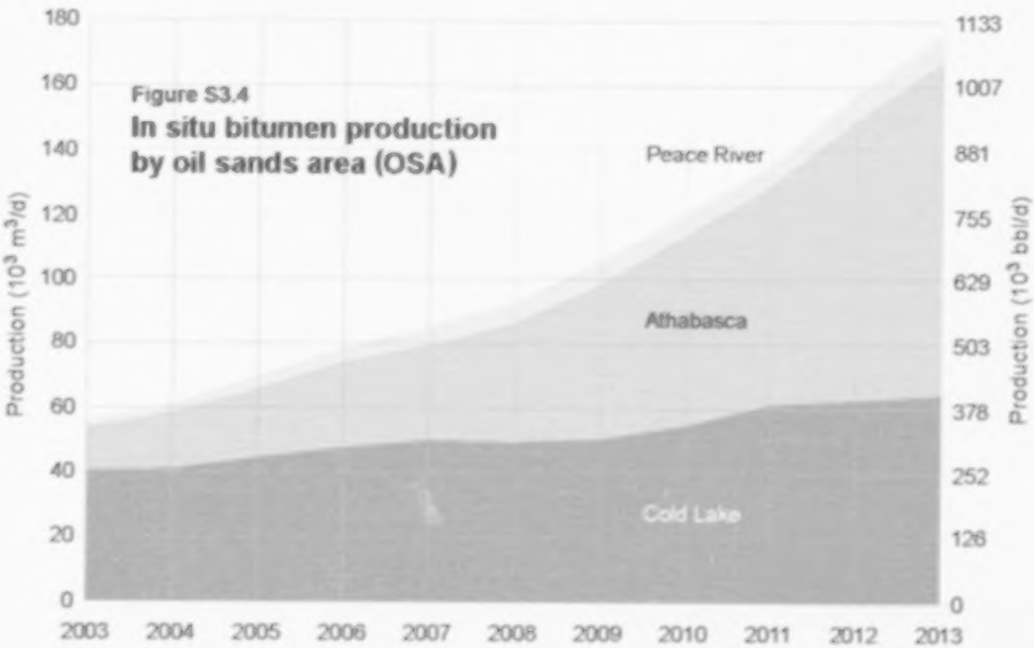


production from 2300 in 1992 to 12 400 in 2013. The average annual productivity of in situ bitumen wells continued to increase, reaching 14.2 m^3/d in 2013, up 4 per cent from 13.7 m^3/d in 2012. This change is due to the increase in the number and proportion of steam-assisted gravity drainage (SAGD) wells, which have higher average productivity rates, compared to cyclic steam stimulation (CSS) wells.

Figure S3.4 shows historical in situ production by OSA. The majority of production continues to come from the Athabasca OSA, accounting for 59 per cent of total production. In 2013, the Athabasca, Cold Lake, and Peace River OSAs produced 103.5 10^3 m^3/d, 64.2 10^3 m^3/d, and 8.5 10^3 m^3/d, respectively. Annual production growth rates for the three OSAs were 19 per cent, 2 per cent, and 6 per cent, respectively. Significant increases in production within the Athabasca OSA since 2003 are due to the expansion of SAGD development.

Currently, there are three main methods for producing in situ bitumen: primary production, CSS, and SAGD. In situ bitumen production by recovery method per year is shown in **Figure S3.5**. Primary production includes those schemes that use water and polymer injection (considered as enhanced recovery) as a recovery method. In 2013, 52 per cent of in situ production was recovered by SAGD, 25 per cent by primary schemes, and 23 per cent by CSS. SAGD production was responsible for 81 per cent of the total increase in production between 2012 and 2013. CSS experienced a slight decline, falling by 1.1 10^3 m^3/d, a 3 per cent decrease, from 2012 production levels.

Figure S3.6 shows the average well productivity in 2013 by recovery method for SAGD, CSS, and primary production (including enhanced recovery). This is calculated by dividing the average daily production on a monthly basis by the average producing well count for the respective month, which is then adjusted to produce an annual average.



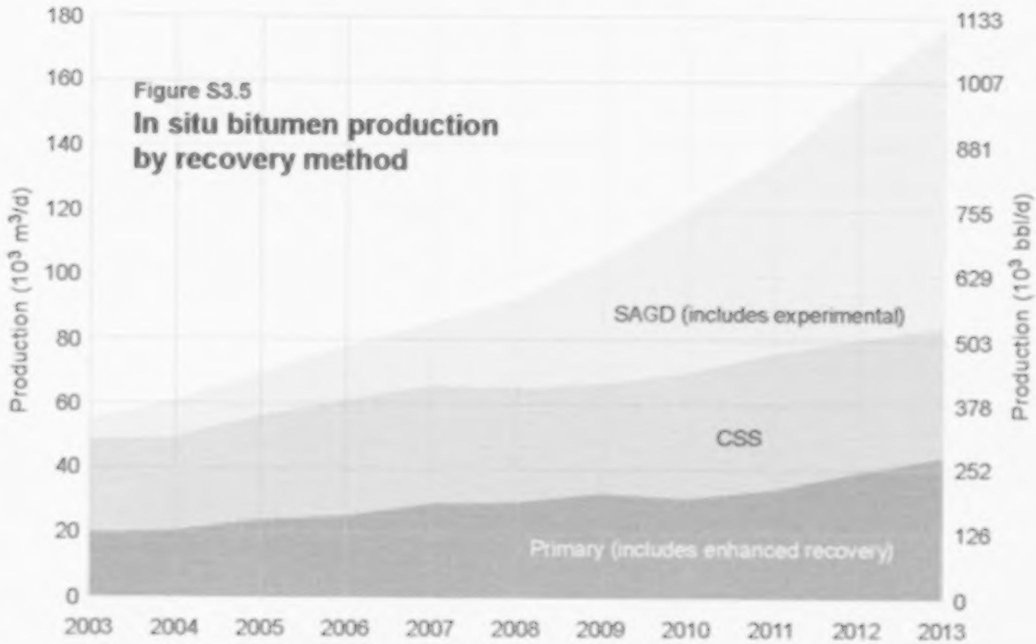


Figure S3.5
In situ bitumen production by recovery method

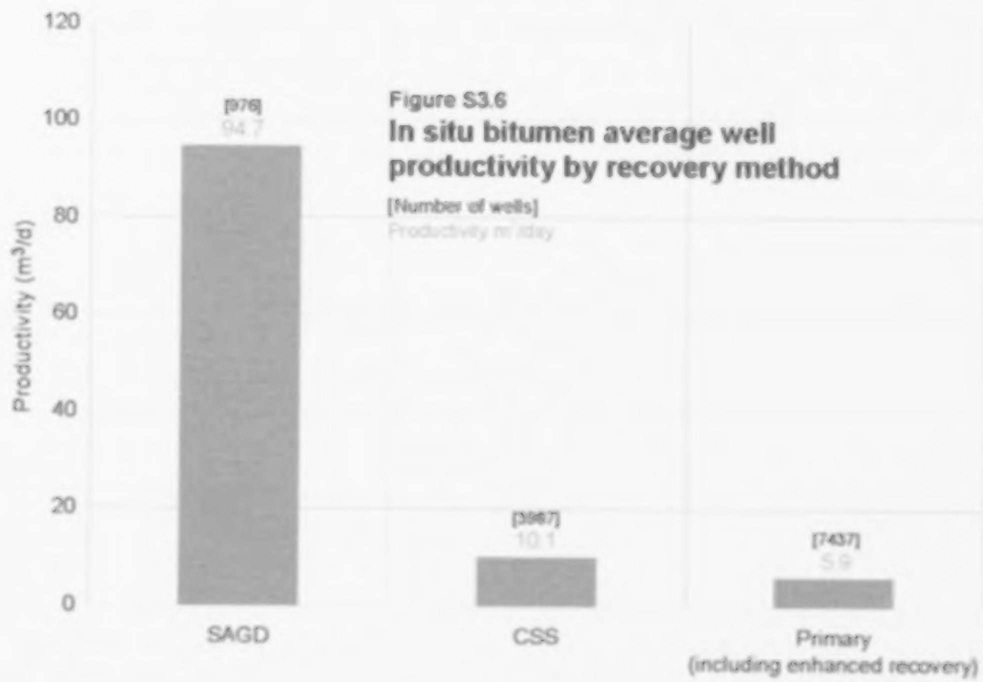


Figure S3.6
In situ bitumen average well productivity by recovery method

3.2.1.3 Upgraded Bitumen

Currently, the majority of Alberta mined bitumen (approximately 97 per cent) and a small portion of in situ production (approximately 12 per cent) are upgraded. Upgraded bitumen production in 2013 averaged 148.8 10^3 m^3/d, compared with the revised total of 145.2 10^3 m^3/d in 2012. **Table S3.1** shows upgraded bitumen production in 2013 by individual operator.

Alberta's five upgraders produce a variety of upgraded products: Suncor produces light sweet and medium sour crudes, including diesel; Syncrude, CNRL Horizon, and Nexen Inc. (Nexen) Long Lake produce light sweet synthetic crude; and Shell produces an intermediate refinery feedstock for the Shell Scotford refinery, as well as sweet and heavy synthetic crude oil. Production from new upgraders is expected to align in response to specific refinery product requirements.

Most of the projects use delayed coking as their primary upgrading technology and achieve volumetric liquid yields (upgraded bitumen produced/bitumen processed) of 80 to 90 per cent, whereas projects employing hydrogen-addition can achieve volumetric liquid yields of 100 per cent or more. The Nexen Long Lake project uses OrCrude™, a carbon rejection upgrading process using conventional thermal cracking, distillation, and solvent deasphalting equipment. A key aspect of this process is the removal of coke precursors (asphaltenes) prior to thermal cracking of the upgrader feed. The total 2013 production of upgraded bitumen of 54.3 10^6 m^3 was produced from 61.8 10^6 m^3 of raw crude bitumen, an 87.9 per cent overall yield.

3.2.1.4 Gasification

Gasification allows companies to convert materials that would otherwise be low-value products into energy sources and reduces the reliance on external energy sources. Gasification can be used to convert asphaltenes, petroleum coke, and vacuum distillation bottoms into a synthetic gas (syn gas) fuel.

The Nexen Long Lake project integrates the gasification of asphaltenes to produce a syn gas that is used in the SAGD and upgrading operations, significantly reducing the amount of natural gas that is required.

Gasification of low-value products is also being planned for the proposed North West Upgrader. The gasifier will produce syn gas and hydrogen from refinery bottoms.

Table S3.1 Average daily upgrader[1] bitumen production in 2013[a]

Company/project name	Production (10^3 m^3/d)
Syncrude	43.6
Suncor	45.9
Shell Canada Scotford	37.7
CNRL Horizon	16.0
Nexen Long Lake	5.6
Total	**148.8**

[a] Any discrepancies are due to rounding.

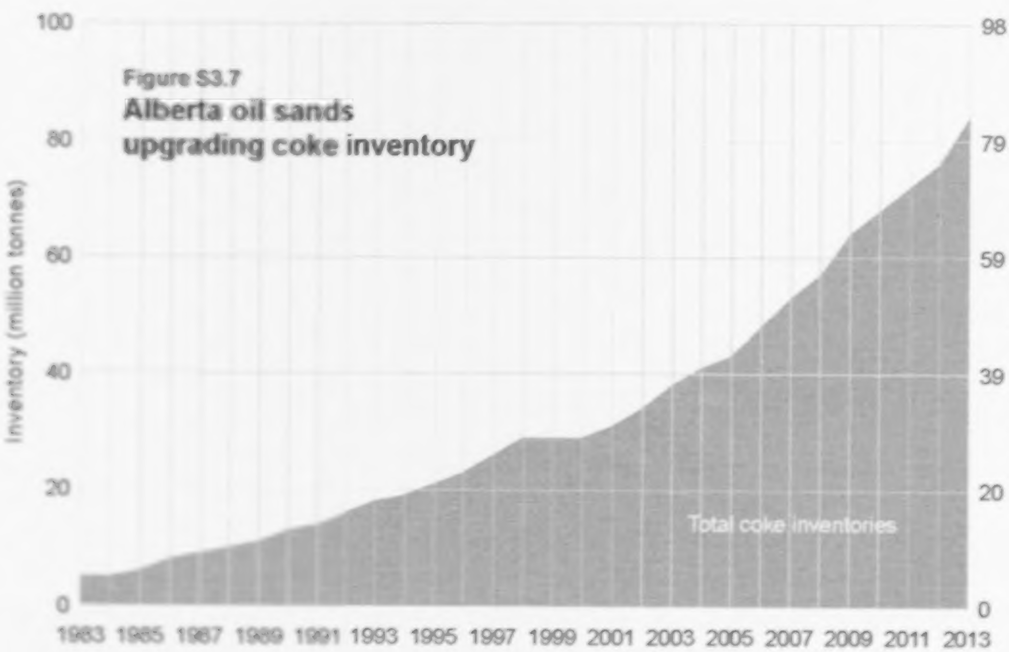
3.2.1.5 Petroleum Coke

Petroleum coke, a by-product of oil sands upgrading, is currently being stockpiled in Alberta because it is considered a potential source of energy. It is high in sulphur but has a lower ash content than conventional crude oil petroleum coke. Suncor, Syncrude, and CNRL Horizon operate oil sands mines near Fort McMurray and have both on-site extraction and upgrading. All three operations produce coke.

Suncor has been burning sulphur-rich coke in its boilers for decades at its mine near Fort McMurray, with about 9 per cent of its annual coke production being used for site fuel in 2013. In addition, Suncor sold about 23 per cent through its energy marketing group. Syncrude began using coke as a site fuel in 1995 and by 2013 used 21 per cent of its annual coke production as site fuel. At CNRL's Horizon project, all coke produced is stockpiled, accounting for about 5 per cent of total coke inventories.

Suncor and Syncrude are exploring new ways to use their coke surplus, including using it as a reclamation material. In 2009, Suncor applied to the AER for permission to use coke inventories for capping two tailings ponds. Suncor estimated that it could use about 40 million tonnes of the coke stockpiled for nonenergy use for reclamation. In 2011, Suncor received partial approval to begin a full-scale operational test on one of the ponds.

Statistics of coke inventories reported in *ST39: Alberta Mineable Oil Sands Plant Statistics* show increases in the total closing inventories per year, as illustrated in **Figure S3.7**. In 2013, coke inventories reached 84 million tonnes, up 7 million tonnes from 2012. This represents a change of about 9 per cent, an increase over the 2012 rate of growth of 6 per cent. As can be seen in **Figure S3.7**, inventories remained constant from 1998 to 2000 due to higher on-site use of coke by the upgraders; however, this has been followed by a trend of rising inventories that is expected to continue unless other usages or markets are developed.



3.2.2 Crude Bitumen Production – Forecast

3.2.2.1 Mined Crude Bitumen

In projecting the future supply of bitumen from mining, the AER considered potential production from existing facilities and supply from future projects. Production from future mining projects considers the high cost of engineering and materials and the substantial amount of skilled labour required to expand existing and new projects. The AER also recognizes that other key factors, such as the forecast of oil prices and the length of the construction period, will affect project timing. Projects that have been approved or have been applied for are considered for inclusion in the forecast. Announced projects are generally not included in AER forecasts. The projects actually considered for the forecast are shown in **Table S3.2**.

Projects awaiting regulatory or corporate approval are generally discounted at 50 per cent, while those under construction or soon to be operating are discounted at rates reflective of past production. Due to uncertainties regarding timing and project scope, some projects, including Teck's Equinox project, have not been considered in the ten-year forecast. If production were to come on stream from these proposed projects, it would be in the latter part of the forecast period.

In projecting total mined bitumen over the forecast period, the AER considered factors such as the crude oil price environment, the availability of export capacity, and the availability of refinery capacity.

By 2023, mined bitumen is expected to reach 264.9 10^3 m^3/d, a slight increase over last year's forecast in which mined bitumen was expected to reach 254.6 10^3 m^3/d by 2022. Mined bitumen production compared to total bitumen production over the forecast period is illustrated in **Figure S3.8**, which shows that the percentage of mined bitumen to total production is expected to decrease from 47 per cent in 2013 to 41 per cent in 2023.

3.2.2.2 In Situ Bitumen

Similar to surface mining, the forecast supply of in situ bitumen includes production from existing projects, expansions to existing projects, and development of new projects. In forecasting production from existing and future schemes, the AER considered all approved projects and projects currently before it for approval. The forecast assumes that existing projects will continue producing at their current or projected production levels over the forecast period. To this projection, the AER has added crude bitumen production from new and expanded schemes. The production forecasts for future crude bitumen projects take into account past experiences of similar schemes, project modifications, crude oil and natural gas prices, light crude and bitumen price differentials, pipeline availability, and the ability of North American markets to absorb the increased volumes.

As illustrated in **Figure S3.8**, the AER expects in situ crude bitumen production to increase to 379.0 10^3 m^3/d by 2023, an increase over last year's forecast of 350.8 10^3 m^3/d in 2022, due to the addition of new projects and the accelerated development schedules for existing and approved projects. Based on this projection, in situ bitumen will account for 59 per cent of total bitumen produced by 2023. Factors that may affect the pace of development were considered in the forecast, such as the availability of labour and equipment.

Table S3.2 Surface mined bitumen projects

Company Project name	Start-up	Capacity (10^3 m^3/d)	Status
Alberta Oil Sands Project (Shell)			
Muskeg River expansion and debottlenecking	TBD[a]	18.3	Approved
Jackpine Phase 1B	TBD	15.9	Approved
Jackpine Phase 2	TBD	15.9	Approved
Pierre River Phase 1	TBD	15.9	Application
Pierre River Phase 2	TBD	15.9	Application
CNRL			
Horizon Phase 2A	2014	21.5	Under construction
Horizon Phase 2B	TBD	21.5	Approved
Horizon Phase 3	TBD	21.5	Approved
Suncor/Total E&P Canada			
Fort Hills Phase 1	TBD	25.4	Approved
Fort Hills debottleneck	TBD	3.2	Approved
Imperial Oil/Exxon Mobil			
Kearl Phase 1	2013	17.5	Operating
Kearl Phase 2	TBD	17.5	Approved
Kearl Phase 1 debottleneck 1	TBD	4.5	Approved
Kearl Phase 1 debottleneck 2	TBD	5.0	Approved
Kearl Phase 2 debottleneck 1	TBD	4.5	Approved
Kearl Phase 2 debottleneck 2	TBD	5.0	Approved
Total E&P Canada/Suncor			
Joslyn (North)	TBD	15.9	Approved
Teck Resources Limited			
Frontier Phase 1	TBD	11.9	Application
Frontier Phase 2	TBD	13.3	Application
Frontier Phase 3	TBD	12.6	Application
Frontier Phase 4	TBD	6.3	Application

Source: AER and company releases.
[a] To be determined.

Projects that have been approved are considered for inclusion in this forecast. Announced projects are generally not included in the forecast. Projects awaiting regulatory or corporate approval are generally discounted at 50 per cent, while those under construction or soon to be operating are discounted at rates reflective of past production. The projects considered for the forecast are shown in **Table S3.3.**

In 2013, approximately 12 per cent of in situ production in Alberta was upgraded, mostly from Suncor's Firebag project. The percentage of in situ bitumen upgraded is expected to vary throughout the forecast period, before reaching about 7 per cent in 2023, which is lower than the projection in the 2012 forecast due to an increase in the AER's forecast for in situ production.

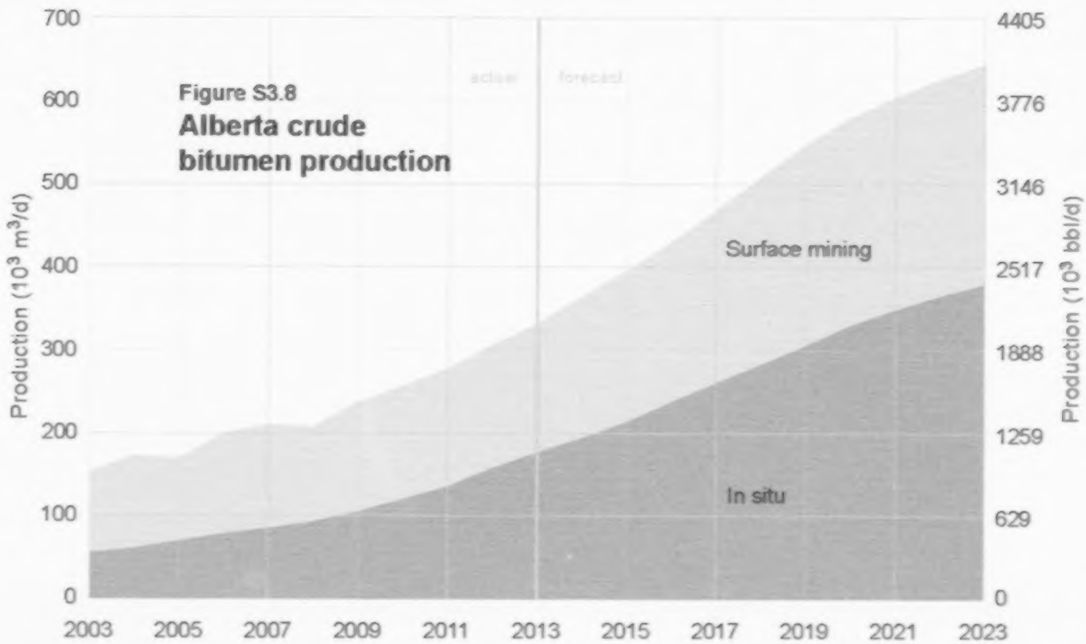


Figure S3.8
Alberta crude bitumen production

Table S3.3 In situ crude bitumen projects

Company Project	Start-up	Capacity (10^3 m^3/d)	Status
Athabasca Oil Sands Area			
Alberta Oil Sands			
Clearwater West	TBD[a]	1.6	Application
Athabasca Oil			
Dover Clastics	TBD	1.9	Application
Hangingstone	TBD	1.9	Approved
BlackPearl			
Blackrod Commercial Phase 1–3	TBD	12.8	Application
Brion Energy (formerly Dover Operating Co.)			
Dover Phases 1–5 (approved in early 2014)	TBD	40.0	Approved
MacKay River Phase 1	2015	5.6	Under construction
MacKay River Phases 2–4	TBD	18.4	Approved
Cavalier			
Hoole Grand Rapids	TBD	1.6	Application
Cenovus			
Christina Lake Phase F	2016	7.9	Under construction
Christina Lake Phase G	TBD	7.9	Approved
Foster Creek Phase F	2014	5.6	Under construction

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Table S3.3 (*continued*)

Company Project	Start-up	Capacity (10^3 m^3/d)	Status
Foster Creek Phase G	2015	5.6	Under construction
Foster Creek Phase H	TBD	5.6	Approved
Narrows Lake Phase 1A and 1B	TBD	10.3	Approved
Pelican Lake Grand Rapids Phases A–C	TBD	9.5	Application
Telephone Lake Phases A and B	TBD	7.2	Application
CNRL			
Grouse Stage 1	TBD	7.9	Application
Kirby North and South Phase 2	TBD	15.2	Application
Connacher			
Great Divide Expansion Phases 1–3	TBD	3.8	Application
ConocoPhillips			
Surmont Phase 2	2014	17.3	Under construction
Devon			
Jackfish 3	2014	5.6	Under construction
Pike 1 Phases A–C	TBD	16.8	Application
Walleye	TBD	1.4	Application
Grizzly Oil Sands			
Algar Phases 1 and 2	TBD	0.9	Approved
May River Phase 1	TBD	1.6	Approved
Harvest			
BlackGold Phase 1	2014	1.6	Under construction
BlackGold Phase 2	TBD	3.2	Approved
Husky			
Sunrise Phase 1	2014	9.5	Under construction
Sunrise Phases 2–4	TBD	22.2	Approved
Imperial			
Aspen Phases 1–3	TBD	21.6	Application
Ivanhoe			
Tamarack Phases 1 and 2	TBD	3.2	Application
JACOS			
Hangingstone Expansion	TBD	5.6	Approved
Koch Exploration			
Muskwa	TBD	1.6	Application
Laricina			
Germain Phases 2–4	TBD	23.8	Application
Saleski Phase 1	TBD	2.0	Approved

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Table S3.3 *(continued)*

Company Project	Start-up	Capacity (10^3 m^3/d)	Status
Marathon			
Birchwood	TBD	1.9	Application
MEG			
Christina Lake Phase 3A–3C	TBD	23.7	Approved
Surmont Phases 1–3	TBD	19.5	Application
Nexen			
Kinosis Phase 1A	2014	3.2	Approved
Kinosis Phases 1 and 2	TBD	19.0	Approved
Osum			
Sepiko Kesik	TBD	9.6	Application
Statoil			
Kai Kos Dehseh Leismer Commercial	TBD	1.6	Approved
Kai Kos Dehseh Leismer Expansion	TBD	3.2	Approved
Kai Kos Dehseh Corner	TBD	6.4	Approved
Suncor			
Firebag Phases 5 and 6	TBD	19.8	Approved
MacKay Phase 2	TBD	6.4	Approved
Sunshine Oilsands			
Legend Lake	TBD	1.6	Application
Thickwood	TBD	1.6	Approved
West Ells Phases 1 and 2	TBD	1.6	Approved
Surmont Energy			
Wildwood	TBD	1.9	Application
Value Creation			
Terre de Grace Phase 1	TBD	1.6	Approved
Advanced TriStar	TBD	11.9	Application
Cold Lake Oil Sands Area			
Husky			
Caribou Lake Phase 1	TBD	1.6	Approved
Imperial			
Cold Lake Phases 14–16	TBD	4.8	Approved
Koch Exploration			
Gemini Phase 2 (incl. pilot)	TBD	1.8	Approved
Osum			
Taiga Phase 1 and 2	TBD	7.2	Approved
Pengrowth			

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Table S3.3 (*continued*)

Company Project	Start-up	Capacity (10^3 m^3/d)	Status
Lindbergh	TBD	2.0	Application
Shell			
Orion (Hilda Lake) Phase 2	TBD	1.6	Approved
Peace River Oil Sands Area			
Penn West			
Seal Main Commercial	TBD	1.6	Application
Shell Peace River			
Carmon Creek Phases 1 and 2	TBD	10.6	Approved

Source: AER and company releases.

[a] To be determined.

3.2.2.3 Upgraded Bitumen

To forecast upgraded bitumen production, the AER includes existing production from the Suncor, Syncrude, Shell, CNRL, and Nexen projects plus their planned expansions, as well as the new production expected from projects listed in **Table S3.4**. Production from future upgrading projects considers the high cost of engineering and materials and the substantial amount of skilled labour required to expand existing and new projects. The AER also recognizes that other key factors, such as oil price forecasts, the price differential between light crude oil and bitumen, the length of the construction period, and the market penetration of new upgraded volumes, will affect project timing.

Companies have begun to express interest in partial upgrading. Partial upgrading involves the removal of asphaltenes, along with other heavier organic compounds, to lower the viscosity of the crude bitumen enough so that it flows in pipelines without the need for diluent. Partial upgrading offers significant cost savings over the building of a full upgrader and produces a crude oil consistent with traditional heavy oils. Current partial upgrading proposals include Value Creation's Terre de Grace and Advanced TriStar projects, as well as MEG's HI-Q demonstration pilot project.

Over the forecast period, the percentage of crude bitumen upgraded is expected to decline from 52 per cent of total crude bitumen in 2013 to 36 per cent in 2023. This is a result of growth in production of bitumen outpacing the growth in upgrading capacity.

Figure S3.9 shows the AER's projection of upgraded bitumen production, which is expected to increase from 148.8 10^3 m^3/d in 2013 to 153.9 10^3 m^3/d in 2014. This increase assumes operators are able to reach their planned production targets. Production is forecast to increase to 208.7 10^3 m^3/d by 2023. This is fairly consistent with last year's end of forecast projection of 200.8 10^3 m^3/d by 2022.

Table S3.4 Upgraded bitumen projects

Company Project	Start-up	Upgrading capacity (10^3 m^3/d)	Status
Athabasca Region			
CNRL			
Horizon Phase 2A	2014	1.6	Approved
Horizon Phase 2B and 3	TBD[a]	19.9	Approved
Nexen/OPTI			
Long Lake Phase 2	TBD	9.3	Approved
Value Creation			
Terre de Grace	TBD	1.3	Approved
Advanced TriStar	TBD	10.2	Application
Industrial Heartland Region			
North West Upgrading			
NW Upgrader Phase 1	2016	7.4	Approved
NW Upgrader Phase 2 and 3	TBD	14.8	Approved

Source: AER and company releases.

[a] To be determined.

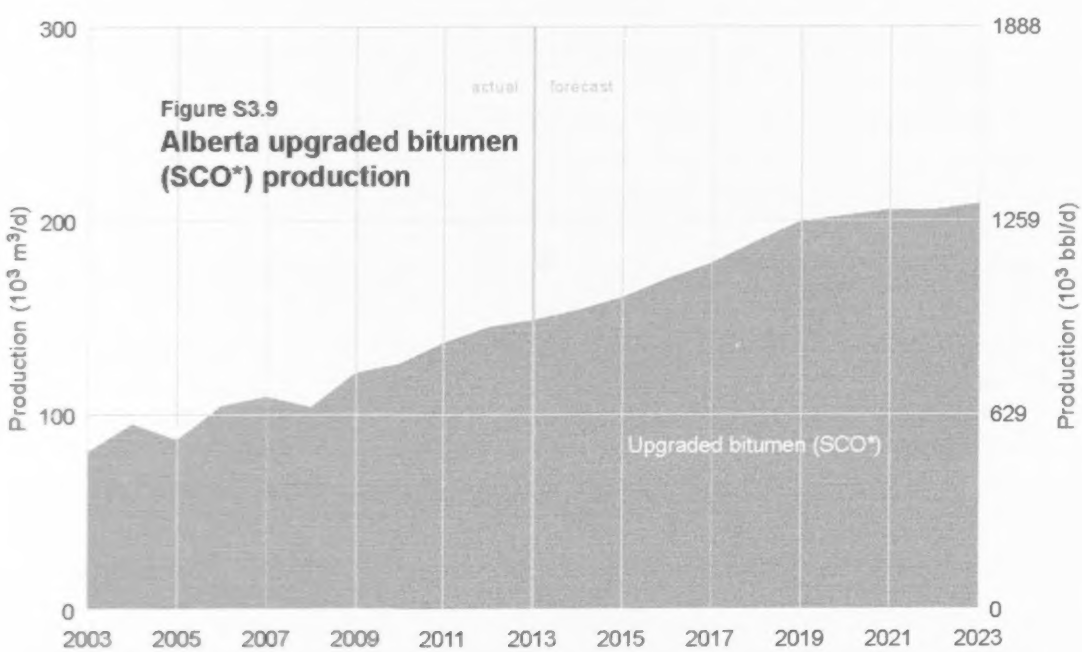


Figure S3.9
Alberta upgraded bitumen (SCO*) production

*Synthetic crude oil.

3.2.3 Supply Costs

The supply cost for a resource project can be defined as the minimum constant dollar price required to recover all capital expenditures, operating costs, royalties, and taxes, as well as to earn a specified return on investment. The supply cost calculation determines a value received per unit of production. For SAGD and standalone mining, this involves solving for a bitumen price at plant gate. To provide a more meaningful comparison, the results of the supply cost analysis have been converted to a West Texas Intermediate (WTI) price. This price can then be compared with current market prices to assess whether a project or resource is economically attractive. It can also be used for comparative project economics.

3.2.3.1 Assumptions

Although each project is unique in its location and the quality of its reserves, the supply cost analysis relies on more generic project specifications and capital and operating cost estimates.

The generic projects represent proposed project types, including in situ SAGD (with and without cogeneration) and standalone mining with cogeneration. An integrated mine was not considered for this analysis as there are currently no proposed integrated bitumen projects in Alberta. Although significant production currently comes from CSS projects, few new CSS projects have been proposed; therefore, supply costs have not been determined for this recovery method. The wide range in SAGD capital costs represents the current economic environment in which producers are pursuing additional phases, as well as green field development, with the lower range of the capital cost being applicable to phased additions where portions of the infrastructure are already in place.

A major component of operating costs is purchased natural gas for fuel and feedstock. This analysis assumes an average value of Cdn$3.84 per gigajoule real Alberta reference price over a project's 30- to 40-year life. For 2013 and beyond, the analysis assumes a nominal discount rate of 10 per cent.

3.2.3.2 Results

The results of the AER's supply cost analysis for crude bitumen projects are shown in **Table S3.5**. Results are provided in both metric and imperial units since North American price data are based on a US$ WTI. The input cost data and the resultant supply cost outputs are in 2013 dollars. The supply costs calculated for 2013 have increased over those calculated last year. In situ supply costs have increased by approximately $5/bbl to reflect

Table S3.5 Crude bitumen supply costs, 2013

	Production		Capital cost range (millions of dollars)	Capacity utilization	Estimated supply cost ($US WTI equivalent per barrel)	Purchased natural gas requirement	
Project type	(10^3 m^3/d)	(bbl/d)				(10^3 m^3 gas/ m^3 oil)	(mcf/bbl)
In situ SAGD	4.8	30 000	800–1 750	90%	55–85	0.177–0.354	1.0–2.0
Standalone mine	15.9	100 000	6 500–8 400	90%	75–105	0.071–0.106	0.4–0.6

higher capital and operating costs, while the range for mining has increased substantially to reflect higher capital costs associated with projects currently underway.

Given the current and forecast high oil prices **Table S3.5** shows that the ongoing development of many in situ and mining projects is still supported. However, some higher cost projects may be delayed or cancelled.

A major risk to the capital cost assumptions in this analysis would be the re-emergence of the cost escalation that occurred in the last decade. When too many projects proceed, resources such as labour quickly become scarce, which results in an escalation in capital and supply costs.

3.2.4 Demand for Upgraded Bitumen and Nonupgraded Bitumen

As upgraded bitumen (synthetic crude oil) is a light sweet crude oil and blended bitumen (nonupgraded bitumen with diluent) is a heavy crude oil, Alberta's crude bitumen and conventional crude oil production often services the same refineries and uses the same transportation infrastructure to make it to market. Consequently, when considering existing and potential future markets for bitumen and upgraded bitumen, production of conventional crude oils, especially heavier crude oils, must be accounted for in the analysis.

Overall demand for Alberta upgraded bitumen and blended bitumen is influenced by many factors, including the price differential between light and heavy crude oil, the expansion of refineries currently processing upgraded bitumen and blended bitumen, the altering of current light crude oil refineries to process upgraded bitumen and blended bitumen, and the availability and price of diluent for shipping blended bitumen. The supply forecast is dependent on demand growth within Alberta in addition to the ability of Alberta production to find export markets.

In 2013, the four refineries in Alberta, with a total capacity of 72.7 10^3 m^3/d, used 46.9 10^3 m^3/d of upgraded bitumen and 3.0 10^3 m^3/d of nonupgraded bitumen. Additional demand for upgraded bitumen as diesel fuel and plant fuel accounted for 5.5 10^3 m^3/d in 2013, compared with 5.8 10^3 m^3/d in 2012, a decrease of 5 per cent. Alberta refineries consumed 32 per cent of Alberta upgraded bitumen production and 2 per cent of nonupgraded bitumen production in 2013, which is unchanged from 2012 levels. Overall, total Alberta demand for upgraded and nonupgraded bitumen was 55.5 10^3 m^3/d in 2013, which is very similar to the 2012 level of 55.2 10^3 m^3/d.

Upgraded bitumen is also used by the oil sands upgraders as fuel for their transportation needs and as plant fuel. Suncor reports that it sells bulk diesel fuel to companies that transport it to other markets in tanker trucks. Suncor sells diesel fuel supplied from its oil sands operation in the Fort McMurray area. In 2013, the sale of refined upgraded bitumen as diesel fuel oil accounted for about 7 per cent of Alberta upgraded bitumen demand, down from 8 per cent in 2012.

Traditionally removals from Alberta serviced the U.S. Rocky Mountain and the U.S. Midwest regions, with a total capacity of 656 10^3 m^3/d. In addition to western Canada's eight refineries, with a total capacity of 108.5 10^3 m^3/d, Alberta crude oil also supplies four refineries in the Sarnia area of eastern Canada, with a

combined total capacity of 62.6 10^3 m^3/d. In 2013, removals of upgraded bitumen and nonupgraded bitumen amounted to 96.4 10^3 m^3/d and 153.7 10^3 m^3/d, respectively.

Beyond the addition of the Northwest Upgrader, the AER assumes that there will only be limited demand growth in Alberta over the forecast period. As a result, the anticipated growth in supply will be removed from the province to service other markets.

Resurgent light oil supplies in western Canada and the U.S. Midwest have led to an oversupply in what have traditionally been the largest export markets for Alberta upgraded and nonupgraded bitumen. As such, there is increasing interest in accessing other market regions, such as the U.S. Gulf Coast, with a refining capacity of 1387 10^3 m^3/d. Access to this region is of particular importance for nonupgraded bitumen, as this region has refineries capable of handling heavier crude oils. Transportation is going to play a key role in accessing this and additional markets as Alberta producers seek to move beyond their traditional markets.

While the oversupply issue at Cushing, Oklahoma, has eased with the startup of the southern leg of the Keystone XL project (the Gulf Coast project) and the expansion of the Seaway pipeline, limited takeaway capacity has continued to affect the ability of Enbridge to take advantage of unused capacity on the Mainline system prior to Superior, Wisconsin. This is expected to change as pipelines projects aimed at expanding capacity on the Mainline and Lakehead systems are pursued.

These projects include expansions of the Alberta Clipper line and the Southern Access line, in addition to the proposed Flanagan South project, which would mirror the Spearhead pipeline. In addition to Enbridge's projects aimed at accessing the Gulf Coast markets, completion of the northern leg of TransCanada's Keystone XL project, currently awaiting U.S. State Department approval, would provide Alberta producers direct access to the U.S. Gulf Coast markets.

Beyond accessing the Gulf Coast markets, considerable attention is being given to accessing markets not traditionally served by Alberta production, including the East Coast, the West Coast, and Asian markets. Among the projects aimed at providing access to the East Coast is the proposed conversion of a portion of TransCanada's mainline system to oil service, dubbed the Energy East project and the proposed reversal of Lines 9A and 9B by Enbridge. Projects aimed at accessing the West Coast and points beyond include Enbridge's proposed Northern Gateway pipeline and Kinder Morgan's proposed expansion to its TransMountain pipeline. Both projects would provide port access for Alberta production allowing it to access international markets. **Figure S3.10** shows proposed removal pipeline expansions and new pipeline removal projects. Pipeline capacities and proposed start-up dates are listed in **Table S3.6**. Further information regarding Alberta's petroleum pipelines can be found in the new Infrastructure section, **Section 9.1.1.1.**

Rail shipments represent a small but significant portion of total volumes of oil moved from Alberta. At present, rail is primarily being used to service projects with limited or no access to pipeline capacity. However, this is expected to change in the near term as producers such as Southern Pacific, MEG Energy, and Cenovus contract rail transport to secure transportation for their production and to access higher value markets. In the longer term, however, growth in shipments of oil by rail will depend on several factors, such as the availability and supply

of diluent, the prices offered by other commodity producers already using rail, and the development of handling facilities to fill cars with bitumen. In 2013, Canexus finished expansions to its rail terminal capacity at its Bruderheim facility (northeast of Edmonton), and Keyera's South Cheecham Rail and Truck Terminal (southeast of Fort McMurray) opened. Future projects include Gibson's Hardisty Rail Terminal and Kinder Morgan's Edmonton Rail Terminal both slated to open in 2014.

Figure S3.11 shows that by 2023, Alberta demand for upgraded and nonupgraded bitumen will increase to about 65.1 10^3 m^3/d. It is projected that, on average, upgraded bitumen will account for approximately 84 per cent of total Alberta demand, and nonupgraded bitumen will account for approximately 16 per cent throughout the forecast period. Removals of upgraded bitumen from Alberta are expected to increase from 96.4 10^3 m^3/d in 2013 to 153.7 in 2023, with removals of nonupgraded bitumen increasing from 157.8 10^3 m^3/d to 391.2 10^3 m^3/d over the same period.

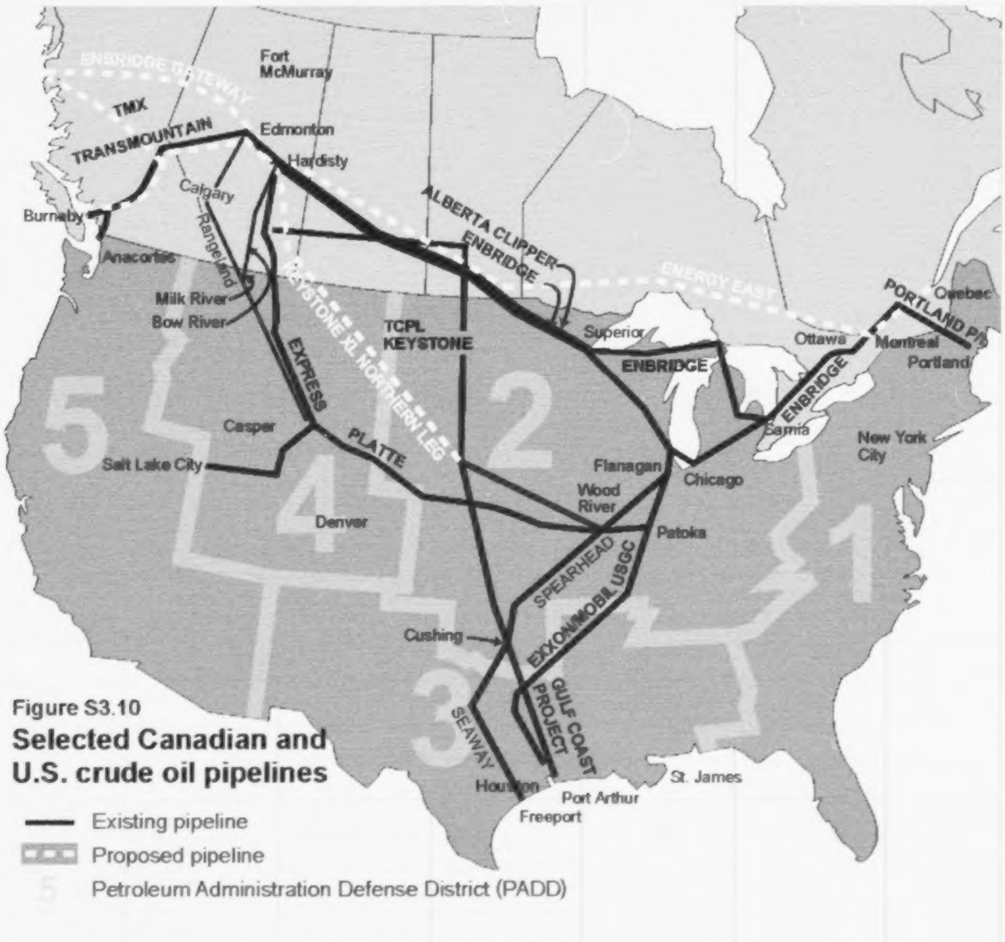


Figure S3.10
Selected Canadian and U.S. crude oil pipelines

Table S3.6 Selected North American pipeline system developments

Company Project	Start-up	Capacity (10^3 m^3/d)	Origin	Destination
Enbridge				
Spearhead North	2014	37.3	Flanagan, Il	Cushing, OK
Flanagan South	2014	95.3	Chicago, IL	Cushing, OK
Alberta Clipper Expansion	2015	90.6	Hardisty, AB	Superior, WI
Southern Access	2015	89.0	Superior, WI	Patoka, IL
Line 9A Reversal	TBD	47.7	Sarnia, ON	Westover, ON
Line 9B Reversal	TBD	47.7	Westover, ON	Montreal, QC
Northern Gateway	TBD	83.4	Bruderheim, AB	Kitimat, BC
Kinder Morgan				
TransMountain expansion	2017	141.4	Edmonton, AB	Vancouver, BC
TransCanada				
Energy East	TBD	174.8	Hardisty, AB	Montreal, QC
Keystone XL (northern leg)	TBD	131.9	Hardisty, AB	Steele City, NB

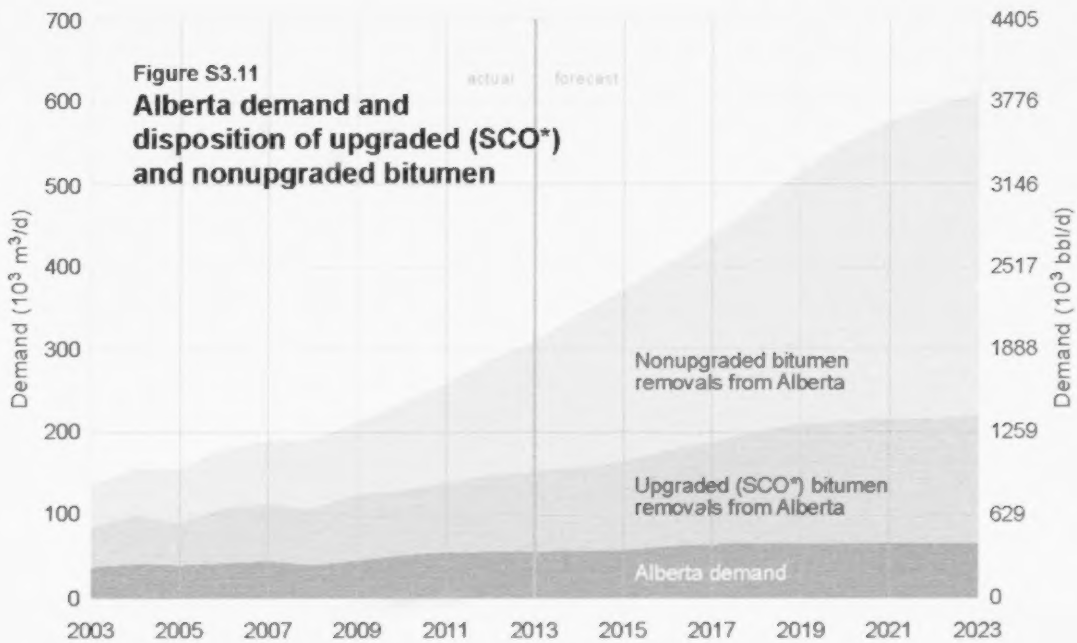


Figure S3.11
Alberta demand and disposition of upgraded (SCO*) and nonupgraded bitumen

*Synthetic crude oil.

4 CRUDE OIL

HIGHLIGHTS

Remaining established reserves increased by over 5 per cent in 2013 to 283 million cubic metres.

Reserves additions from new drilling and enhanced recovery schemes replaced 112 per cent of production in 2013.

Production increased 5 per cent in 2013 compared with 2012.

There were 2867 oil wells placed on production in 2013, a decrease of 14 per cent from 2012.

In Alberta, crude oil (also known as conventional oil) is deemed to be oil produced outside the oil sands areas or, if within the oil sands areas, from formations other than the Mannville or Woodbend. Crude oil is classified as light-medium if its density is less than 900 kilograms per cubic metre (kg/m^3) or as heavy if its density is 900 kg/m^3 or greater.

4.1 Reserves of Crude Oil

4.1.1 Provincial Summary

The AER estimates the remaining established reserves of conventional crude oil in Alberta to be 283.4 million cubic metres (10^6 m^3), representing about one third of Canada's remaining conventional reserves. This is a year-over-year increase of 14.2 10^6 m^3, or 5.3 per cent, and is a result of all reserves additions less production during 2013.

Table R4.1 shows the changes in Alberta's reserves and production of light-medium and heavy crude oil as of December 31, 2013, while **Figure R4.1** shows the province's remaining conventional oil reserves over time. Remaining reserves are now 23 per cent of the peak reserves of 1223 10^6 m^3 set in 1969.

4.1.2 In-Place Resources

The total initial in-place and remaining in-place resources for conventional oil in Alberta stand at 12 510 10^6 m^3 and 9 824 10^6 m^3, respectively. This remaining in-place resource represents a substantial potential for increased recovery through enhanced oil recovery (EOR) or new drilling and completion techniques, such as high-density drilling and multistage fracturing. On average, 25 per cent of the total oil in-place in these pools is expected to be recovered with today's technology. Additionally, the shale- and siltstone-hosted hydrocarbon resources study discussed in **Section 2.2.2** identified 67 320 10^6 m^3 of unconventional in-place shale oil resources in six key shale formations in Alberta.

4.1.3 Established Reserves

The initial established reserves attributed to the 810 new oil pools defined in 2013 totalled 4.8 10^6 m^3 (an average of 6 thousand [10^3] m^3 per pool), down from 5.8 10^6 m^3 in 2012. Many of the 810 new oil pools can be attributed to the exploration for and expansion of tight oil plays (reservoirs with low permeability).

Table R4.1 Reserves and production change highlights (10^6 m^3)

	2013	2012	Change
Initial established reserves[a]			
Light-medium	2 562.9	2 525.0	+37.9
Heavy	407.0	396.7	+10.2
Total	**2 969.9**	**2 921.8**	**+48.1**
Cumulative production[a]			
Light-medium	2 345.7	2 320.5	+25.2
Heavy	340.7	332.0	+8.7
Total	**2 686.4**	**2 652.5**	**+33.9**[b]
Remaining established reserves[b]			
Light-medium	217.2	204.5	+12.7
Heavy	66.2	64.7	+1.5
Total	**283.4**	**269.2**	**+14.2**
	(1 783 10^6 bbl)[c]	(1 694 10^6 bbl)[c]	(89 10^6 bbl)[c]
Annual production			
Light-medium	24.9	23.8	+1.1
Heavy	8.9	8.5	+0.4
Total	**33.8**	**32.3**	**+1.5**

[a] Any discrepancies are due to rounding.

[b] May differ from annual production due to amendments to reported production and other reasons.

[c] bbl = barrels.

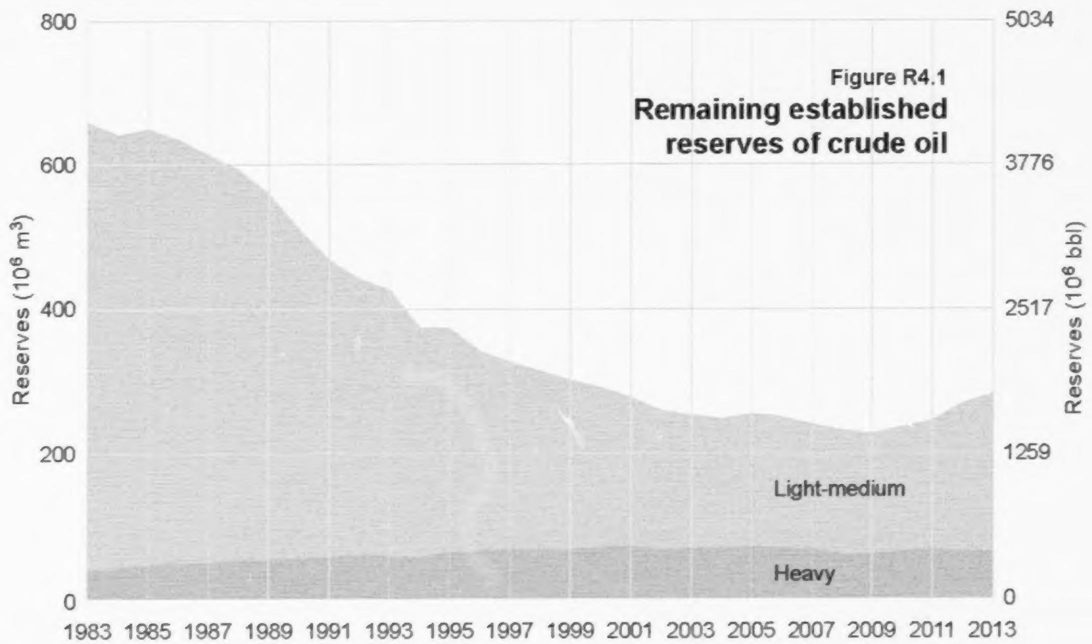


Figure R4.1
Remaining established reserves of crude oil

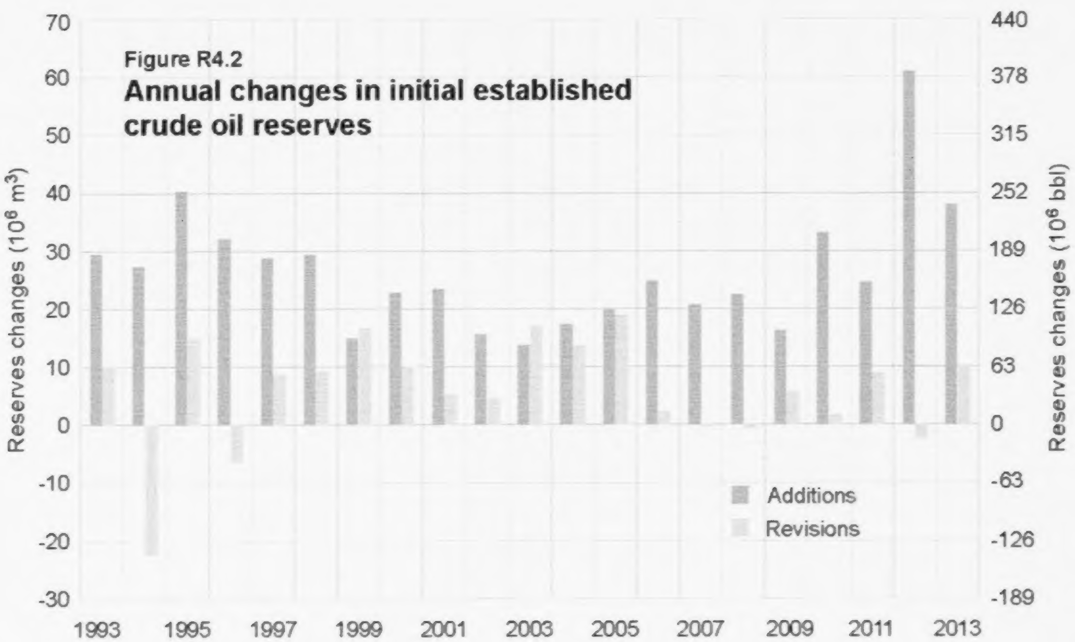
At this time, a significant number of these pools are classified administratively as single well pools but with the potential to be reclassified, based on specific play development, into multiwell pools or plays. **Table R4.2** breaks down the changes to initial established reserves in 2013 into the following categories: new discoveries, development of existing pools, new and expansions to EOR schemes, and revisions to existing reserves. **Figure R4.2** shows the history of additions and net revisions to reserves. Net revisions represent the sum of all negative and positive revisions to pool reserves made over the year.

In 2013, the AER processed 98 applications, higher than the 53 processed in 2012, for new EOR schemes or expansions to existing schemes, resulting in reserves additions totalling 2.2 10^6 m^3, equalling the total in 2012 (**Figure R4.3**). Development of existing pools added established reserves of 30.8 10^6 m^3. This is discussed in more detail in **Section 4.1.3.1**. Total reserves growth from new drilling plus new and expanded EOR schemes (excluding revisions) amounted to 37.9 10^6 m^3, replacing 112 per cent of the 33.8 10^6 m^3 total conventional crude oil production in Alberta. This compares with 189 per cent in 2012 and the previous five-year average

Table R4.2 Breakdown of changes in crude oil initial established reserves (10^6 m^3)

	Light-medium	Heavy	Total*
New discoveries	4.1	0.7	**4.9**
Development of existing pools	24.3	6.5	**30.8**
Enhanced recovery (new/expansions)	1.7	0.5	**2.2**
Revisions	+7.7	+2.4	**+10.1**
Total*	**+37.9**	**+10.2**	**+48.1**

* Any discrepancies are due to rounding.



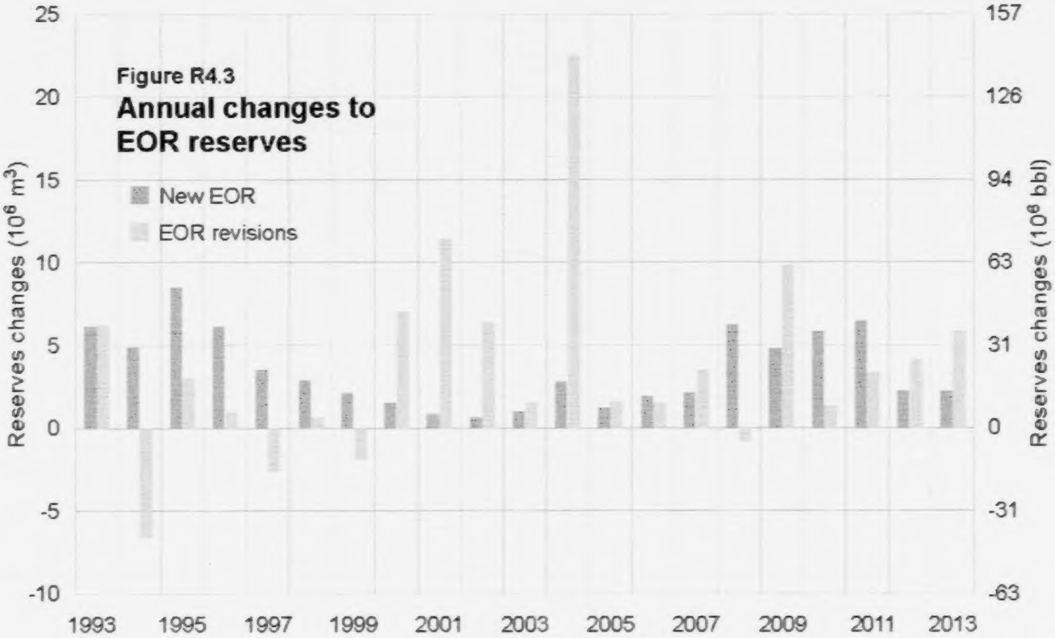


Figure R4.3
Annual changes to EOR reserves

replacement ratio of about 83 per cent. Revisions to existing reserves resulted in an overall net change of +10.1 10^6 m^3. The total increase in initial established reserves for 2013 amounted to 48.1 10^6 m^3, compared with 58.5 10^6 m^3 in 2012. **Table B.3** in **Appendix B** provides a history of conventional oil reserves growth and cumulative production from 1968 to 2013.

As of December 31, 2013, oil reserves were assigned to 11 073 light-medium and 2939 heavy crude oil pools in the province, up from the respective 2012 numbers of 10 570 and 2804. While some of these pools contain thousands of wells, most consist of a single well. About 70 per cent of the province's remaining oil reserves are recoverable from the largest 3 per cent of pools (400 pools), most discovered before 1980. The largest of these pools in terms of remaining reserves continue to be, in decreasing size, Pembina Cardium, Swan Hills Commingled Pool 001, Redwater Commingled Multifield Pool 9508, Ferrier Commingled Pool 001, and Evi Commingled Pool 001.

While the median pool size has consistently been less than 10 10^3 m^3 since the mid-1970s, the average size has declined from 155 10^3 m^3 in 1970 to about 25 10^3 m^3 today. The largest oil pools discovered over the past ten years are the Pembina Cardium JJJ Pool (revised in 2013) and the Judy Creek Beaverhill H Pool, with currently booked remaining reserves of 1379 10^6 m^3 and 1030 10^6 m^3, respectively.

A detailed pool-by-pool list of reservoir parameters and reserves data for all of Alberta's oil pools is available on CD from the AER's Order Fulfillment Team (see **Appendix C**).

4.1.3.1 Largest Reserves Changes

Table R4.3 lists pools with the largest reserves changes in 2013. The most significant change was to the Willesden Green Commingled Pool 007, which saw initial established reserves increase by 2909 10^3 m^3 to 7286 10^3 m^3 as a result of pool development. There continues to be a potential for significant reserves growth from new horizontal drilling in the Cardium Formation at Pembina, Willesden Green, and other surrounding fields. Horizontal, multistage fractured wells are being drilled on the periphery of the main pools, into tight reservoir areas where permeability declines to less than 1 millidarcy (mD) as a result of a change to a shalier facies. Horizontal drilling is also coaxing new reserves from the tighter platform facies in the Lower Banff-Exshaw-Big Valley zone as demonstrated by the 1808 10^3 m^3 increase in reserves in the Ferguson Lwr Banff-Exshaw-BV Pool. The largest negative revision to any pool was 283 10^3 m^3.

Table R4.3 Major oil reserves changes, 2013

Pool	Initial established reserves (10^3 m^3)		Main reason for change
	2013	Change	
Willesden Green Commingled Pool 007	7 286	+2 909	Pool development
Ferguson Lwr Banff-Exshaw-BV	2 110	+1 808	Pool development and new waterflood scheme
Nipisi Gilwood A	60 300	+1 800	Reassessment of reserves
Virginia Hills Beaverhill Lake	2 396	+1 480	Pool development
Harmattan East Cardium C	2 009	+1 446	Pool development and reassessment of reserves
Bantry Mannville A	10 430	+1 305	Pool development
Turner Valley Rundle	30 730	+1 260	Reassessment of waterflood reserves
Elnora Nisku B	1 328	+1 249	Pool development
Sawn Lake	2 956	+1 108	Pool development and reassessment of reserves
Kaybob Triassic G	2 342	+1 037	Pool development
Pembina Commingled Pool 003	19 099	+1 012	Pool development and reassessment of reserves
Lochend Commingled Pool 001	2 256	+840	Pool development
Pouce Coupe South Commingled Pool 012	895	+695	Pool development
Ferrier Commingled Pool 001	19 750	+680	Pool development and reassessment of reserves
Wayne-Rosedale Basal Quartz GG	1 101	+655	Pool development
Lloydminster Commingled Pool 014	2 714	+652	Pool development
Swan Hills South Beaverhill Lake C	1 020	+616	Pool development and reassessment of reserves
Mannville Upper Mannville B	686	+590	Pool development
Countess Upper Mannville YY	2 113	+530	Reassessment of reserves
Westerose South D-3 A	2 536	+480	Pool development and reassessment of reserves
Medicine Hat Glauconitic C	6 279	+478	Reassessment of reserves
Medicine River Commingled Pool 002	3 579	+431	Reassessment of reserves
Redwater Commingled MFP9508	7 696	+392	Pool development
Pembina Cardium JJJ	1 915	+372	Reassessment of reserves
Joffre D-2	8 807	+361	Reassessment of reserves
Edson Commingled Pool 003	1 160	+349	Pool development

4.1.3.2 Distribution by Recovery Mechanism

The overall recovery efficiency for Alberta's conventional crude oil averages 23.8 per cent based on the total initial volume in-place and the initial established reserves of 12 511 10^6 m^3 and 2972 10^6 m^3, respectively. This average overall recovery has been slowly declining over the last decade from an average of 26.6 per cent in 2004. The decline in recovery efficiency is mainly due to the development of reservoirs with lower permeability and porosity (tight plays) within the province. Tight oil plays can limit the ability for enhanced recovery and, therefore, diminish the overall provincial recovery factor. **Figure R4.4** and **Table R4.4** show the distribution of in-place volumes and reserves by recovery mechanism and crude oil classification.

In light-medium pools under waterflood, recovery increased from an average of 15 per cent under primary depletion to 28 per cent under waterflood. Pools under solvent flood, on average, recovered 12 per cent more than projected theoretical waterflood recovery. Additionally, solvent flooding, as well as gas flooding, is usually only undertaken in pools with better quality reservoir characteristics, as demonstrated by the markedly higher average primary recovery factors.

Primary recovery in heavy crude pools has increased from an average of 8 per cent in 1990 to 11 per cent in 2013 as a result of improved water handling, increased drilling density, and the use of horizontal wells with multistage fracturing. Incremental recovery from all waterflood projects represents about 25 per cent of the province's initial established reserves, while polymer floods are projected to add 5 per cent to the province's recoverable reserves. Alkali surfactant polymer (ASP) flooding is proving to be very effective and becoming more accepted, typically adding 3 to 10 per cent recovery over waterflood. Polymer flooding is most effective and used mainly in heavy oil pools.

4.1.3.3 Distribution by Geological Formation and Area

The distribution of reserves by geological period (**Figure R4.5**) shows that the Cretaceous and Upper Devonian ages provide the major source for remaining conventional oil. Any discrepancy in this data is due to the

Figure R4.4

Initial established crude oil reserves based on recovery mechanisms (10^6 m^3)

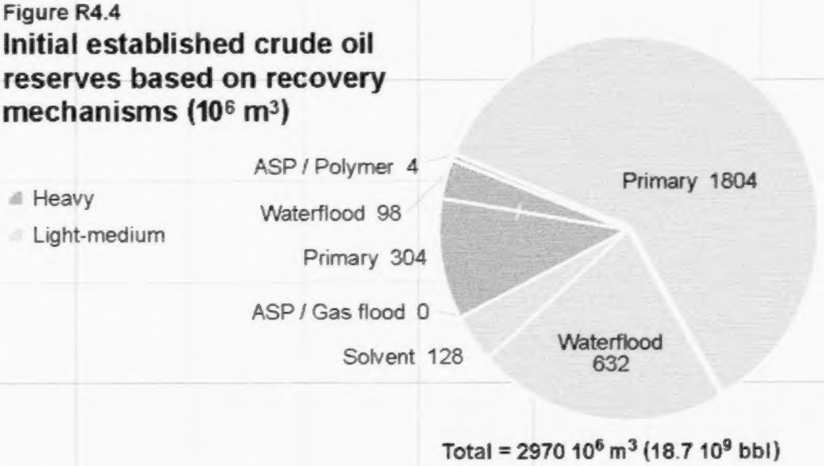


Table R4.4 Conventional crude oil reserves by recovery mechanism as of December 31, 2013

Crude oil type and pool type	Initial volume in-place (10^6 m^3)	Initial established reserves (10^6 m^3)				Average recovery (%)			
		Primary	Water/ gas flood	Solvent flood	Total	Primary	Water/ gas flood	Solvent flood	Total
Light-medium									
Primary	5 264	974	0	0	**974**	18	-	-	**18**
Waterflood	3 447	519	441	0	**960**	15	13	-	**28**
Solvent flood	1 033	273	178	128	**579**	26	17	12	**56**
ASP	9	1	3	0	**4**	11	33	-	**44**
Gas flood	142	38	10	0	**48**	27	7	-	**34**
Heavy									
Primary	1 865	211	0	0	**211**	11	-	-	**11**
Waterflood	695	88	90	0	**178**	13	13	-	**26**
Polymer	25	2	1	3	**6**	8	4	12	**24**
ASP	30	4	6	2	**12**	13	23	3	**39**
Total	**12 510**	**2 109**	**729**	**131**	**2 970**	**17**	**6**	**1**	**24**
Percentage of total initial established reserves		71%	25%	4%	**100%**				

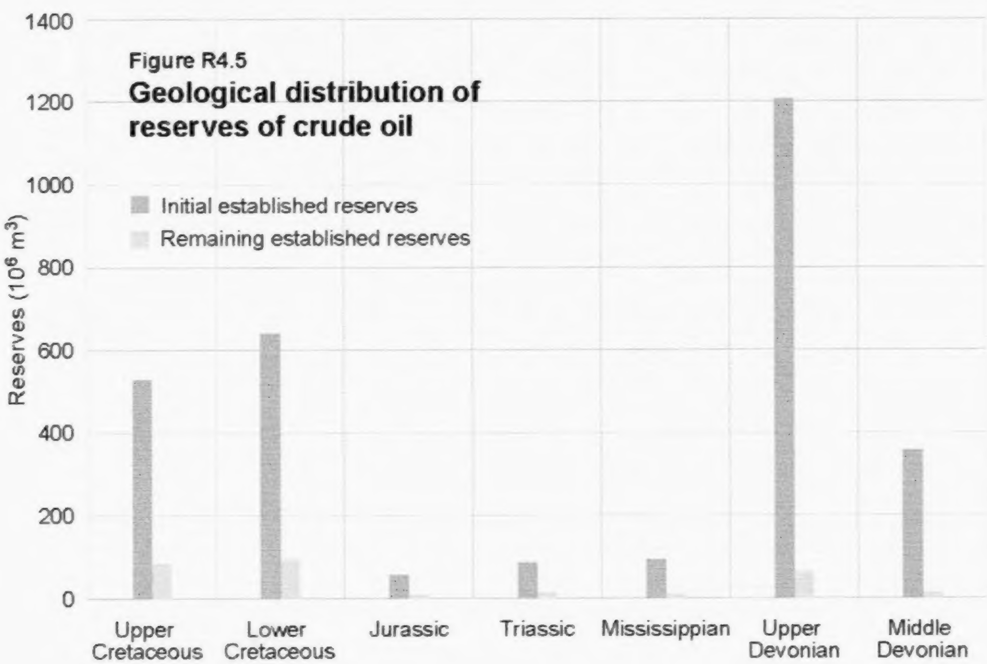


Figure R4.5
Geological distribution of reserves of crude oil

increasing inability to accurately assign reserves into zones that have commingled production. **Figure R4.6** depicts reserves by Petroleum Services Association of Canada (PSAC) area with the central part of the province (PSAC Area 5) containing most of the initial and remaining reserves.

4.1.3.4 Oil Reserves Methodology

The process of quantifying reserves is governed by many geological, engineering, and economic considerations. Initially, there is a higher uncertainty in the reserves estimates, but this uncertainty decreases over the life of a pool as more information becomes available and actual production is observed and analyzed. The earliest reserves estimates are usually based on volumetric estimation. An estimate of bulk rock volume is based on net pay isopach maps derived primarily from geological evaluation of well log data. This is combined with data gathered on rock properties, such as porosity and water saturation, to determine oil in-place at reservoir conditions. Areal assignments for new single-well oil pools range from 64 hectares (ha) for light-medium oil producing from regionally correlatable geological units to 32 ha or less for heavy oil pools and small reef structures.

Converting volume in-place to standard conditions at the surface requires applying oil shrinkage data obtained from pressure, volume, and temperature (PVT) analysis. A recovery factor is applied to the in-place volume to yield recoverable reserves. Oil recovery factors vary depending on oil viscosity, rock permeability, drilling density, rock wettability, reservoir heterogeneity, and reservoir-drive mechanism. Recoveries range from 5 per cent for heavy oils to over 50 per cent for light-medium oils producing from highly permeable reefs with full

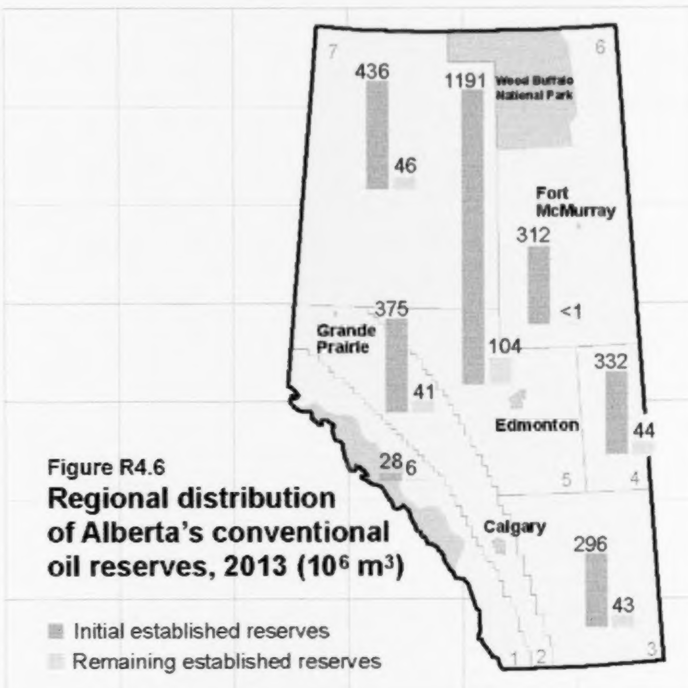


Figure R4.6
Regional distribution of Alberta's conventional oil reserves, 2013 (10^6 m^3)

pressure support from an active underlying aquifer. Provincially, 24 per cent of the in-place resource is recovered on average.

Once there are sufficient pressure and production data, material balance or production decline methods can be used as an alternative to volumetric estimation to determine in-place resources. Analysis by material balance is seldom used as it requires good pressure and PVT data. Production decline analysis, therefore, is the primary method for determining recoverable reserves. When combined with a volumetric estimate of the in-place resource, it also provides a realistic estimate of the pool's recovery efficiency.

Secondary recovery techniques using artificial means of adding energy to a reservoir by water or gas injection can considerably increase oil recoveries. Less common tertiary recovery techniques may be applied by injecting fluids that are miscible with the reservoir oil at high pressures. This improves recovery efficiency by reducing the residual oil saturation at abandonment. However, irregularities in rock quality can lead to channelling, which causes low sweep efficiency and oil to be bypassed in some areas in the pool.

Incremental recovery over primary depletion is estimated for pools approved for waterflood and is displayed separately in the AER's oil reserves database. To accommodate the Alberta government's royalty incentive programs, incremental recovery over an estimated base-case waterflood recovery is determined for tertiary schemes. Typically a base-case waterflood recovery is estimated even in cases where no waterflood was implemented before the solvent flood.

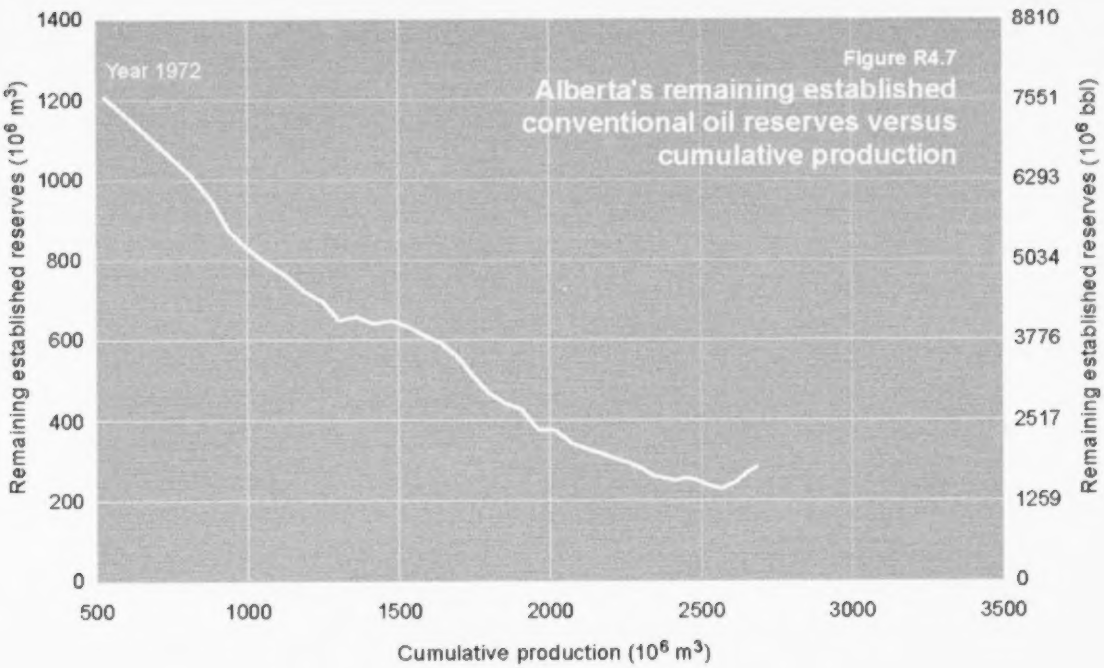
Reserve numbers published by the AER represent estimates for in-place, recoverable reserves and recovery factors based on the most reasonable interpretation of available information from the volumetric, production decline, and material balance methods.

4.1.4 Ultimate Potential

In 1994, based on the geological prospects at that time, the AER estimated the ultimate potential of conventional crude oil to be 3130 10^6 m^3. This estimate only includes conventional reservoirs and does not include oil from tight oil or shale oil plays. Refer to **Section 2.3.3** for a discussion of the ultimate potential for oil within the shale and siltstone portion of the Montney Formation in Alberta. **Figure R4.7** illustrates the historical decline in remaining established reserves relative to cumulative oil production.

4.2 Supply of and Demand for Crude Oil

In projecting crude oil production, the AER considers two components: expected crude oil production from existing wells at year-end and expected production from new wells. Total forecast production of crude oil is the sum of these two components. Demand for crude oil in Alberta is based on provincial refinery capacity and use. Alberta crude oil supply in excess of Alberta demand is marketed outside the province.



4.2.1 Crude Oil Production – 2013

Starting in 2010, total crude oil production in Alberta reversed the downward trend that has been the norm since the early 1970s. Since 2010, conventional crude oil production has increased as a result of increased horizontal drilling activity and with the introduction of multistage hydraulic fracturing technology. Total crude oil production increased by 5 per cent in 2013 to 92.5 10^3 m^3/d from 88.4 10^3 m^3/d in 2012. Light-medium crude oil production increased 5 per cent to 68.3 10^3 m^3/d and heavy crude oil production also increased, rising 4 per cent to 24.3 10^3 m^3/d. These increases occurred even though the number of successful wells drilled decreased significantly in 2012 and 2013 because of the successful application of the more productive technology.

4.2.1.1 Drilling Activity

In 2013, 2523 successful oil wells were drilled, a decrease of 12 per cent from 2012. **Figure S4.1** shows the number of successful oil wells drilled in Alberta in 2012 and 2013 by PSAC geographical area. With the exception of PSAC Area 4, all areas of the province in which drilling occurred experienced substantial decreases over last year's levels.

Figure S4.2 depicts the distribution of new crude oil wells placed on production and **Figure S4.3** shows the initial operating day rates of new wells in 2013. The number of oil wells placed on production in a given year generally tends to follow crude oil well drilling activity, as most wells are put on production shortly after being drilled. In 2013, the number of wells placed on production decreased by 14 per cent, from 3107 in 2012 to 2667 in 2013.

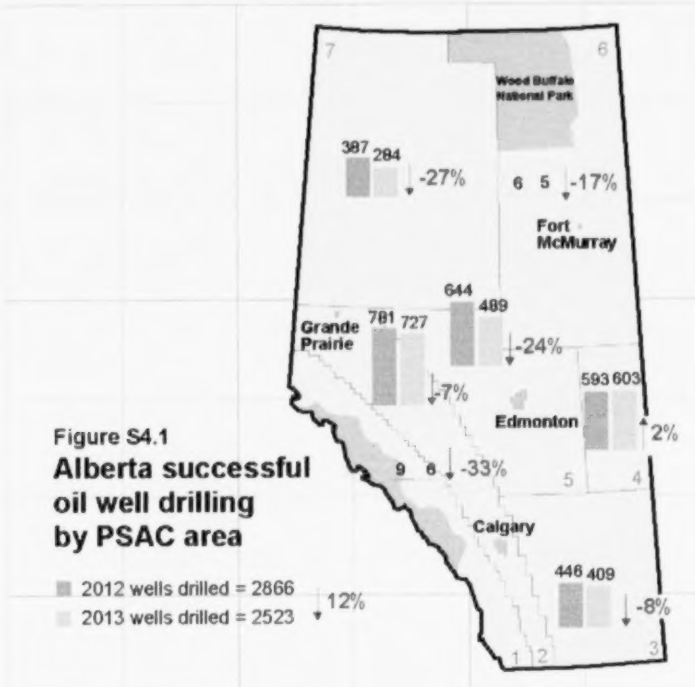


Figure S4.1
Alberta successful oil well drilling by PSAC area

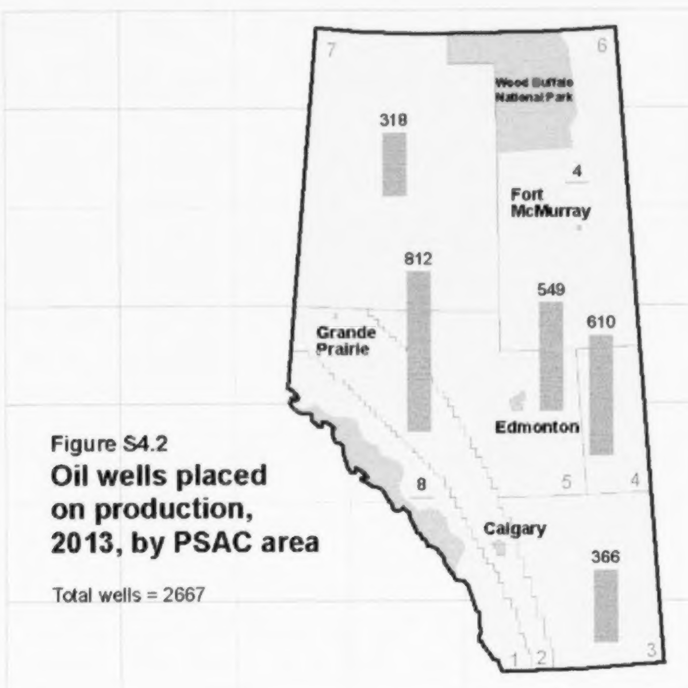


Figure S4.2
Oil wells placed on production, 2013, by PSAC area

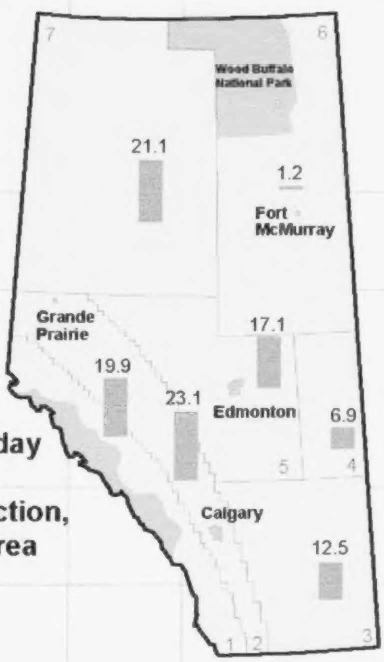


Figure S4.3
Initial operating day rates of oil wells placed on production, 2013, by PSAC area (m^3/day)

4.2.1.2 Production Characteristics

Historical oil production by PSAC area is illustrated in **Figure S4.4**. In 2013, all PSAC areas experienced increases in production when compared to 2012 levels, ranging from a 1 per cent increase in PSAC Area 4 to a 15 per cent increase in PSAC Area 2.

Figure S4.5 shows the total average daily production rate and the number of wells producing crude oil. Initial average daily production rates were calculated for new wells, using the first full calendar year of production. The number of wells producing oil has increased over time from 9100 in 1970 to 42 327 in 2013.

In addition to the 42 327 crude producing oil wells in 2013, about 2549 wells classified as gas wells were producing oil. Although these gas wells represented 6 per cent of the total wells that produced oil, they produced at a very low average rate of 0.2 m^3/d and accounted for less than 1 per cent of total production. About 11 516 producing horizontal oil wells, despite representing only 27 per cent of producing oil wells, contributed almost 53 per cent to the total crude oil production because of the higher average production rate per well. This is a substantial increase from 47 per cent in 2012 and 33 per cent in 2011.

The average daily production rate per well in 1973 for all producing oil wells was 23 m^3/d. This average declined to 5.5 m^3/d by 1991, reaching its lowest level of 1.9 m^3/d by 2009 where it remained until 2011 when it began to increase as a result of the increasing use of more productive technology.

Figure S4.6 depicts producing oil wells and the average daily production rates of those wells by region in 2013. The average well productivity of producing oil wells in 2013 was 2.2 m^3/d, about 10 per cent higher than the

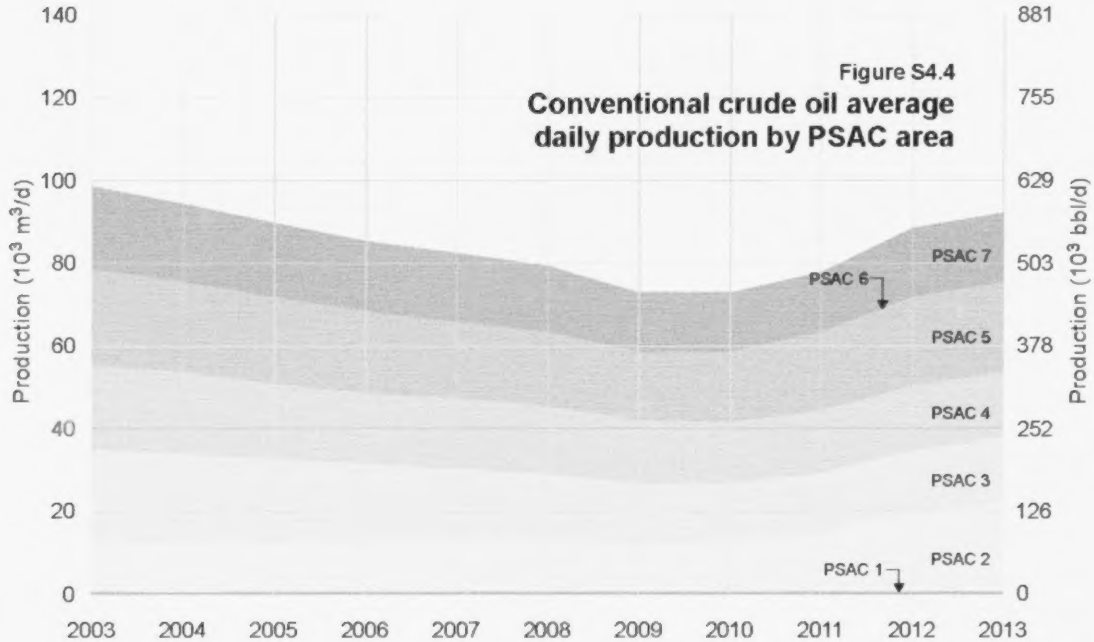


Figure S4.4
Conventional crude oil average daily production by PSAC area
Production (10^3 m^3/d)
Production (10^3 bbl/d)
PSAC 7
PSAC 6
PSAC 5
PSAC 4
PSAC 3
PSAC 2
PSAC 1
140
120
100
80
60
40
20
0
881
755
629
503
378
252
126
0
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013

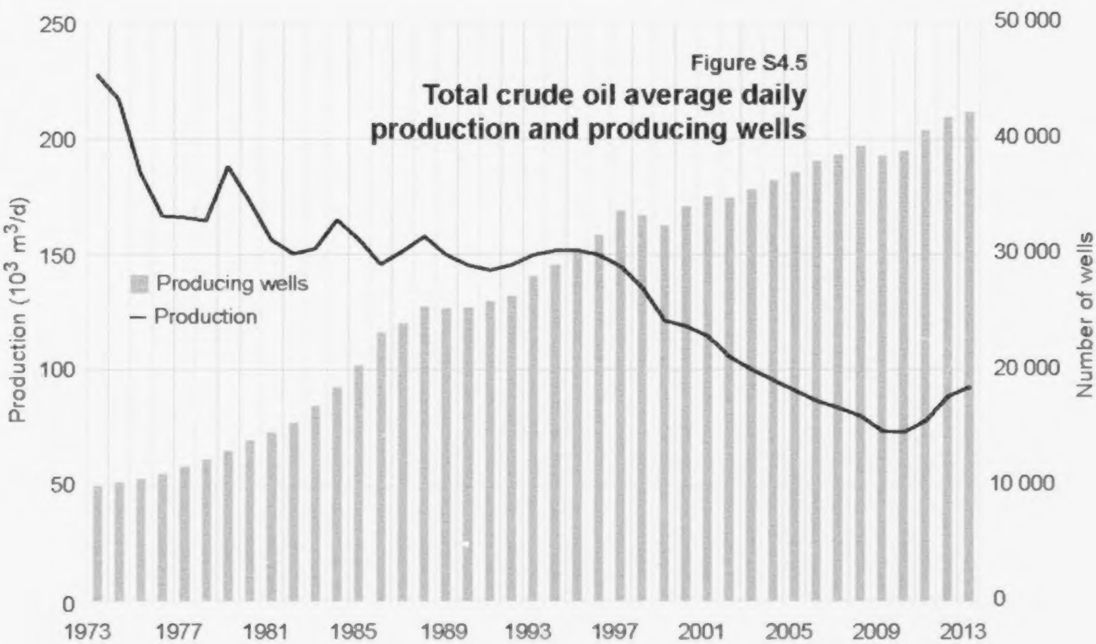


Figure S4.5
Total crude oil average daily production and producing wells
Producing wells
Production
Production (10^3 m^3/d)
Number of wells
250
200
150
100
50
0
50 000
40 000
30 000
20 000
10 000
0
1973
1977
1981
1985
1989
1993
1997
2001
2005
2009
2013

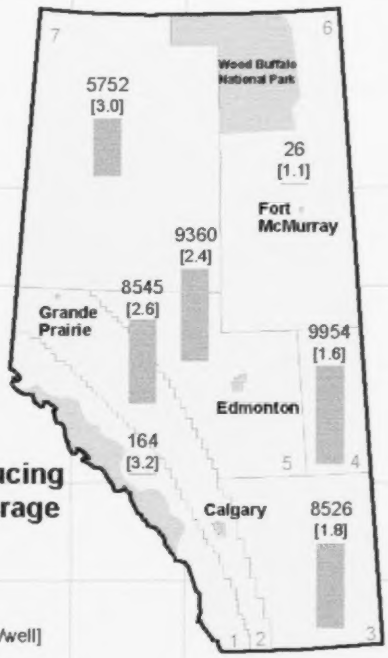


Figure S4.6
Number of producing oil wells and average day rates, 2013, by PSAC area
Total wells = 42 327
Average day rates [m³/day/well]

previous three years. Roughly 44 per cent of producing oil wells produce at rates less than 1 m^3/d per well, a characteristic typical of mature basins. In 2013, the 17 423 oil wells in this category produced at an average rate of 0.6 m^3/d and accounted for only 11 per cent of the total crude oil produced. **Figure S4.7** shows the distribution of crude oil producing wells (including horizontal oil wells) based on their average production rates in 2013.

In 2013, 2150 horizontal oil wells (including those using multistage fracturing technology) were brought on production, a decrease of 10 per cent from the 2012 level of 2379 horizontal wells. This raises the total number of horizontal wells to 11 516.

For horizontal wells placed on production in 2012 (the year of latest data), the initial production rate was 7.5 m^3/d compared with 3.3 m^3/d for vertical wells.

Crude oil production from existing wells placed on production from 2004 to 2013 is depicted in **Figure S4.8**. This figure illustrates that wells placed on production in the last five years represented 53 per cent of crude oil production in 2013. This is the first time the majority of production has been coming from the more recent wells placed on production. In previous years, the production from the wells placed on production in the last five years has been 48 per cent and 41 per cent in 2012 and 2011, respectively.

Figure S4.9 compares historical Alberta crude oil production with crude oil production from Texas onshore and North Dakota. North Dakota production was relatively flat from 1983 to 2007; however, since around 2008, production has escalated rapidly, and 2013 production levels are about seven times the 2007 production levels due to the successful application of horizontal multistage fracturing technology. North Dakota's monthly oil

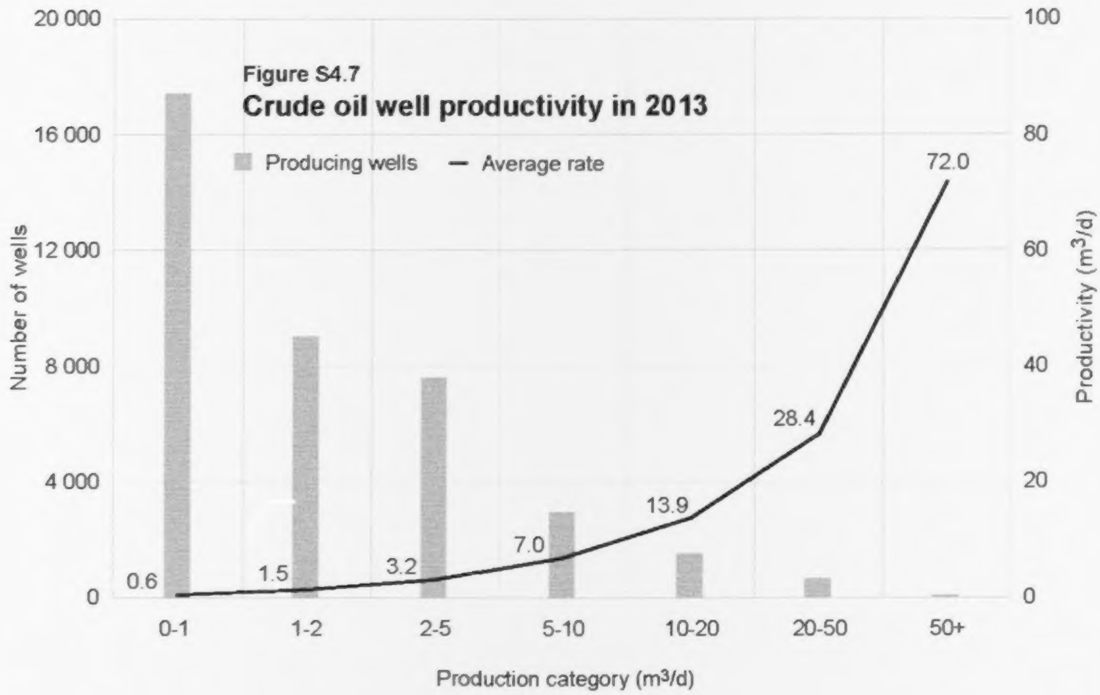


Figure S4.7
Crude oil well productivity in 2013
Producing wells
Average rate
20 000
16 000
12 000
8 000
4 000
0
Number of wells
100
80
60
40
20
0
Productivity (m3/d)
0.6
1.5
3.2
7.0
13.9
28.4
72.0
0-1
1-2
2-5
5-10
10-20
20-50
50+
Production category (m3/d)

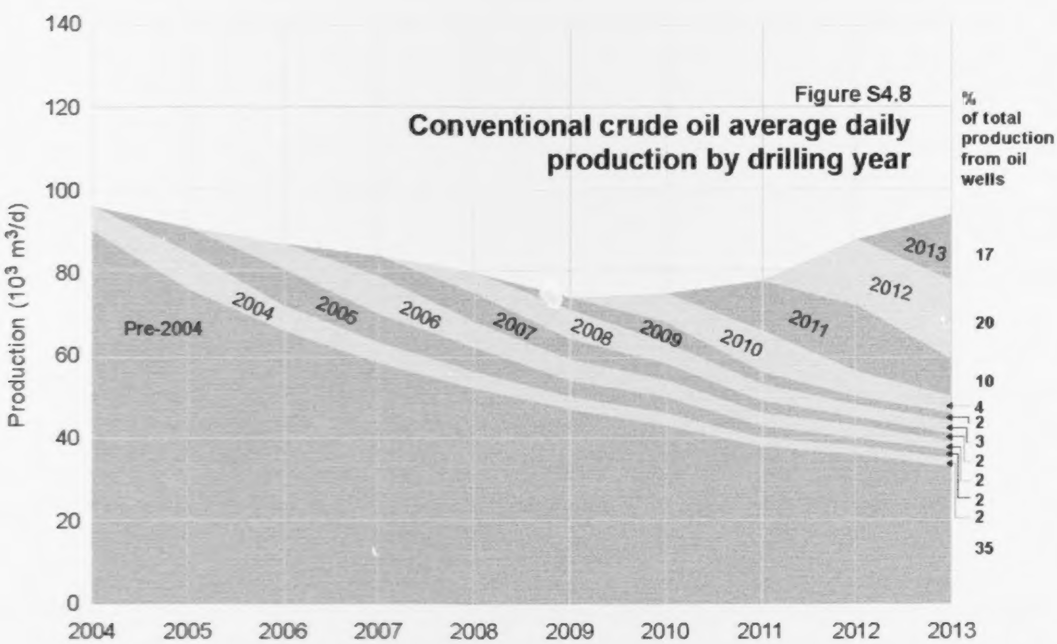
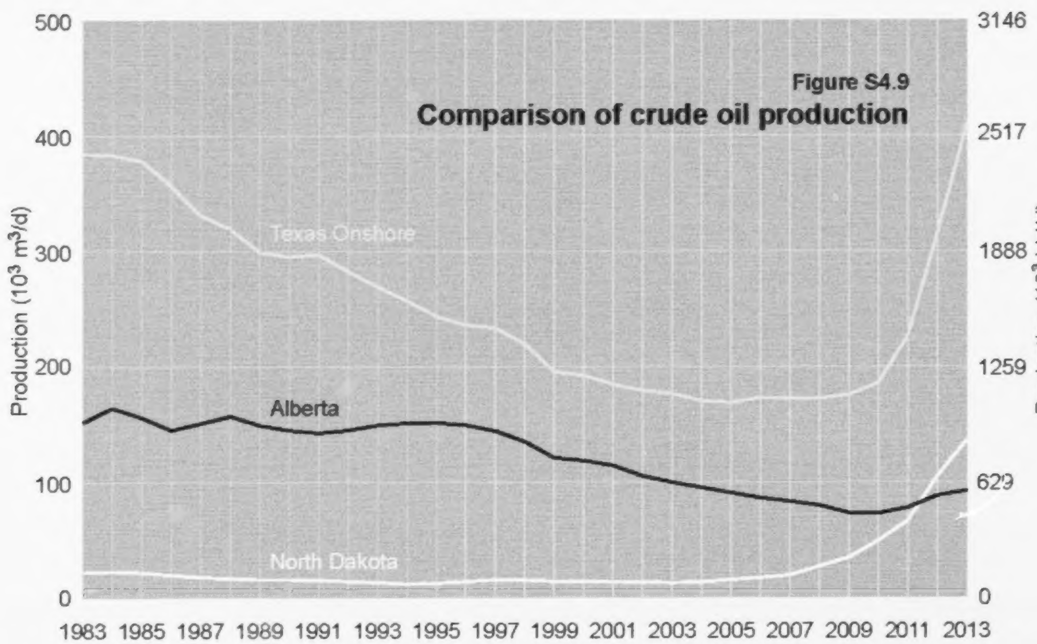


Figure S4.8
Conventional crude oil average daily production by drilling year
% of total production from oil wells
Production (10³ m³/d)
140
120
100
80
60
40
20
0
Pre-2004
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
17
20
10
4
2
3
2
2
2
2
35
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013



production surpassed Alberta's conventional oil production in early 2012 and by late 2013 it was nearly 48 per cent higher. Although it was anticipated that the above increase could result in reduced U.S. demand for Alberta's crude oil, 2013 crude oil exports to the U.S. increased over 2012 levels. Since 2010, Texas onshore and Alberta production have also reversed the downward production trend, again exhibiting outstanding growth in Texas and continued growth in Alberta in 2013.

Figure S4.10 shows the oil production profiles for the first 35 months for a representative sample set of vertical and horizontal oil wells in the Pembina Field that are producing crude oil from the Cardium Formation. Oil wells that were placed on production within the 2010 to 2013 period were used to illustrate the difference in production profiles by well type.

Total production from new wells is a function of the number of new wells that are anticipated to be placed on production, initial production rates, and the expected average decline rates for these new wells.

4.2.2 Crude Oil Production – Forecast

In projecting crude oil production over the forecast period, the AER has separated production from vertical wells from horizontal wells. The forecast for production from new vertical wells acknowledges industry's continued interest in drilling for oil using conventional technology. The horizontal category of wells includes traditional and multistage fractured horizontal wells.

To forecast production from each category, production from existing and new wells placed on production each year has been analyzed. The number of wells placed on production and the average productivity of the wells in each category were the main factors used to project oil production over the forecast period.

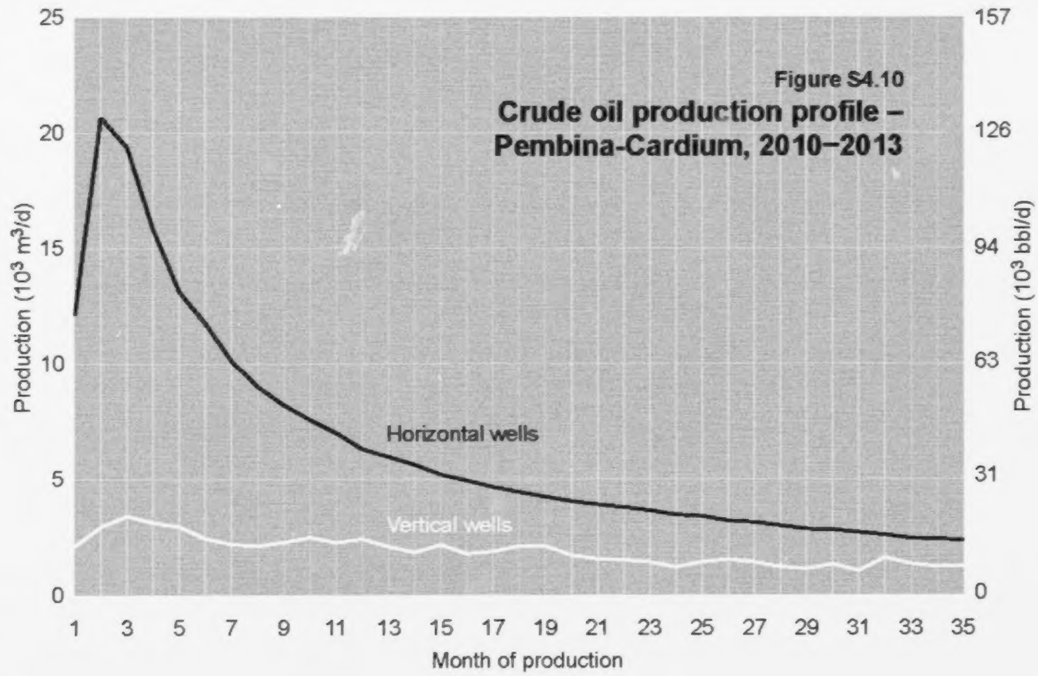


Figure S4.10
Crude oil production profile – Pembina-Cardium, 2010–2013

4.2.2.1 Vertical Wells

Figure S4.11 illustrates the projected crude oil production from vertical wells. The AER based its projection on the following assumptions:

- Production from existing vertical wells will decline by 13.0 per cent per year.
- The number of new vertical oil wells placed on production is projected to decrease from 517 in 2013 to 513 in 2014 and is expected to decline to 442 wells in 2023. This well count is about 15 per cent lower than last year's forecast and reflects the recent decline in the number of crude oil licences issued by the AER, a decreasing trend in number of wells placed on production in the last two years, and also the view that many new wells will be horizontal wells using multistage fracturing technology.
- The average initial production rate for new vertical wells is projected to be 3.3 m^3/d per well in 2014 and is expected to decline to 3.0 m^3/d for the remainder of the forecast period.
- Production from new wells will decline at a rate of 28 per cent the first year, 25 per cent the second year, 24 per cent the third year, 22 per cent the fourth year, 20 per cent the fifth year, 18 per cent the sixth year, and 16 per cent over the rest of the forecast period.

4.2.2.2 Horizontal Wells

A methodology similar to that used for vertical wells is used to project crude oil production from horizontal wells (both traditional and multistage fractured). Potential crude oil production from existing and new wells is combined to project total production in this category of wells over the forecast period.

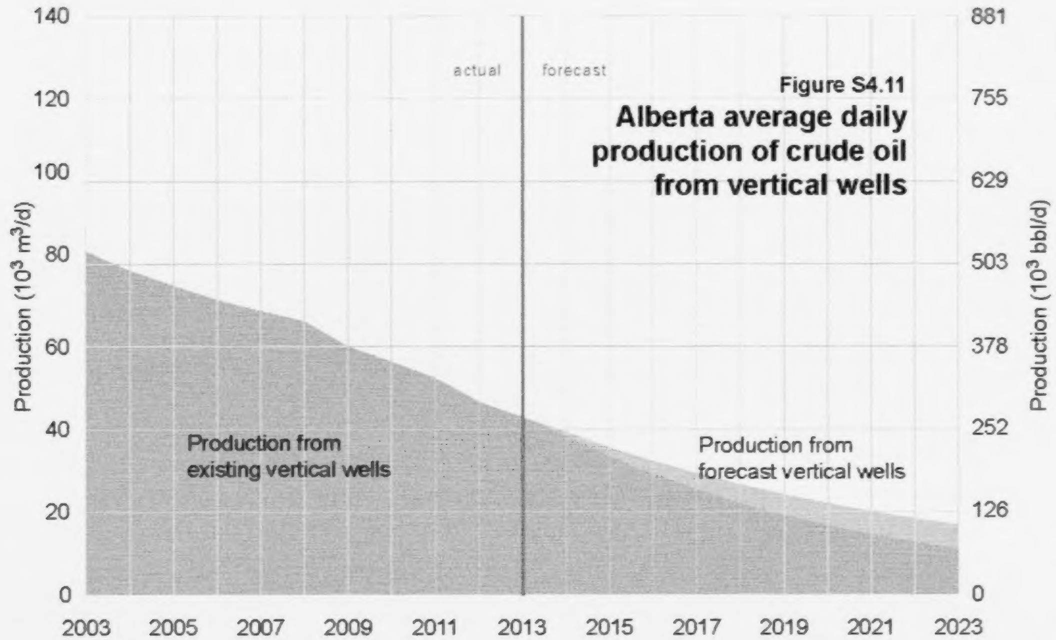


Figure S4.12 illustrates the projected crude oil production from horizontal wells. The AER based its projection on the following assumptions:

- Production from existing wells will decline at a rate of 21.0 per cent per year.
- The number of new horizontal oil wells placed on production is projected to increase from 2150 in 2013 to 2187 in 2014, and to continue to increase until it peaks at 2241 in 2019 and 2020. This number is then expected to decline to 2158 in 2021 and remain at that level for the rest of the forecast period. The forecast number of horizontal oil wells has slightly increased relative to the forecast made in last year's report. This reflects actual activity in 2012 and 2013, industry's projection of increased horizontal drilling, and the expectation of continued strong crude oil prices.
- The average initial production rate for new conventional horizontal wells is projected to be 7.5 m^3/d per well in 2014 and to decline to 6.0 m^3/d per well by the end of forecast period.
- Production from new wells will decline at a rate of 43 per cent the first year, 27 per cent the second year, 18 per cent the third year, 15 per cent the fourth year, 12 per cent the fifth year, and 10 per cent over the remaining forecast period.

4.2.2.3 Production

The projected total crude oil production, which comprises production from both existing wells and new vertical and horizontal wells, is illustrated in **Figure S4.13**. Based on actual activities and industry projections, the production forecast is slightly lower than what was forecast last year, with production in 2014 forecast at

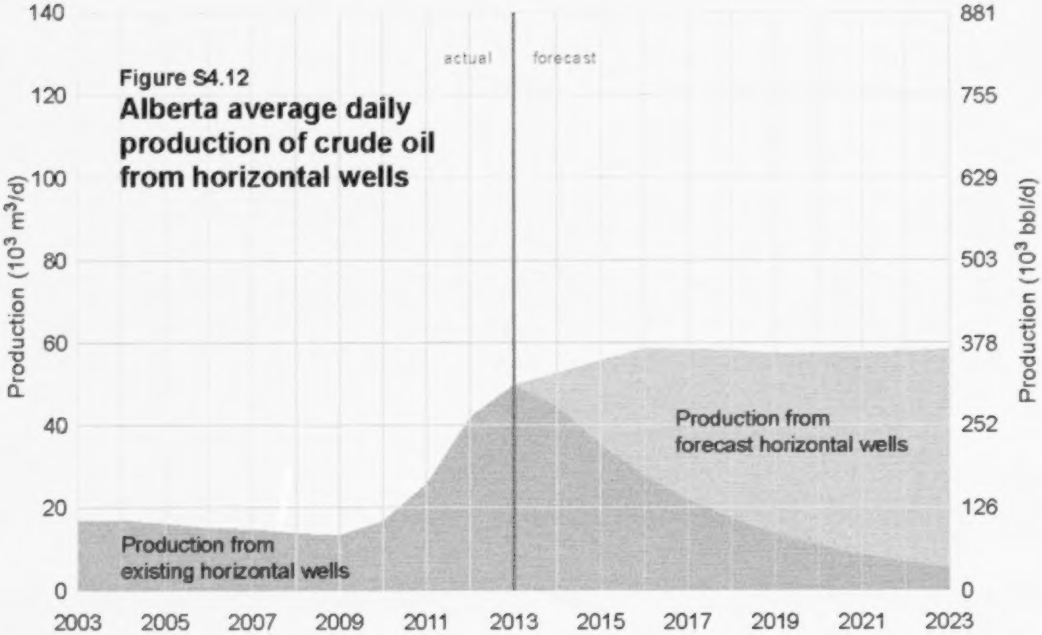


Figure S4.12
Alberta average daily production of crude oil from horizontal wells
actual
forecast
Production from forecast horizontal wells
Production from existing horizontal wells
Production (10³ m³/d)
Production (10³ bbl/d)
140
120
100
80
60
40
20
0
881
755
629
503
378
252
126
0
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023

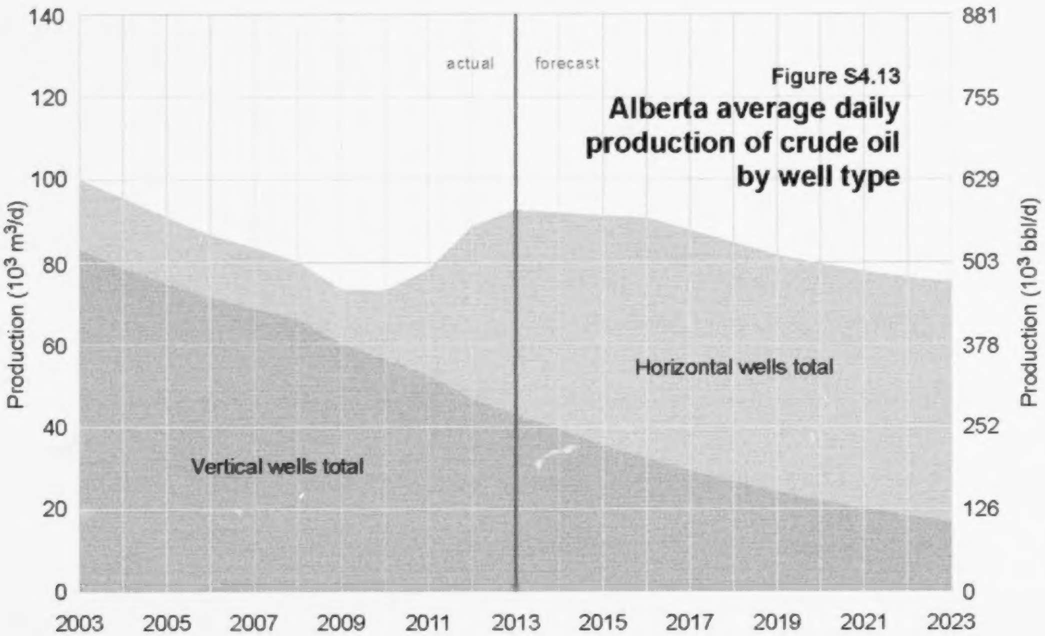


Figure S4.13
Alberta average daily production of crude oil by well type
actual
forecast
Horizontal wells total
Vertical wells total
Production (10³ m³/d)
Production (10³ bbl/d)
140
120
100
80
60
40
20
0
881
755
629
503
378
252
126
0
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023

91.8 10^3 m^3/d compared with last year's forecast of 93.1 10^3 m^3/d for the same year. This trend is consistent with last year's forecast where 2013 was expected to be the year production would reach its peak and decline slowly for the remainder of the forecast period.

Figure S4.14 illustrates the split for light-medium and heavy crude oil. Light-medium crude oil production is expected to slightly increase from 68.28 10^3 m^3/d in 2013 to 68.39 10^3 m^3/d in 2014, and decline to 57.82 10^3 m^3/d in 2023. Over the forecast period, heavy crude oil production is expected to decline to 23.4 10^3 m^3/d in 2014 from 24.26 10^3 m^3/d in 2013 and continue to decline to 17.27 10^3 m^3/d. **Figure S4.14** also illustrates that heavy crude oil production's proportion of total conventional crude oil production in Alberta will gradually decrease from 25 per cent in 2014 to 23 per cent in 2023.

This production forecast assumes that crude oil production will decrease by less than 1 per cent in 2014, down from the actual increase of 5 per cent in 2013, due to an anticipated decrease in the number of wells placed on production in 2014 and higher decline rates for both existing wells and new wells. Crude oil production is expected to decline at an average rate of between 2 to 4 per cent over the remainder of the forecast period. This is a reflection of the lower levels of drilling activity expected over time, higher decline rates, and lower average initial production rates forecast for new horizontal wells. The combined forecasts for existing and future wells indicate that total crude oil production will be 91.8 10^3 m^3/d in 2014, 91.1 10^3 m^3/d in 2015, and gradually decrease to 75.09 10^3 m^3/d in 2023.

Figure S4.15 illustrates the annual number of new wells expected to be placed on production from 2014 to 2023 and includes the forecast for West Texas Intermediate (WTI) crude oil price. In spite of a strong crude oil price

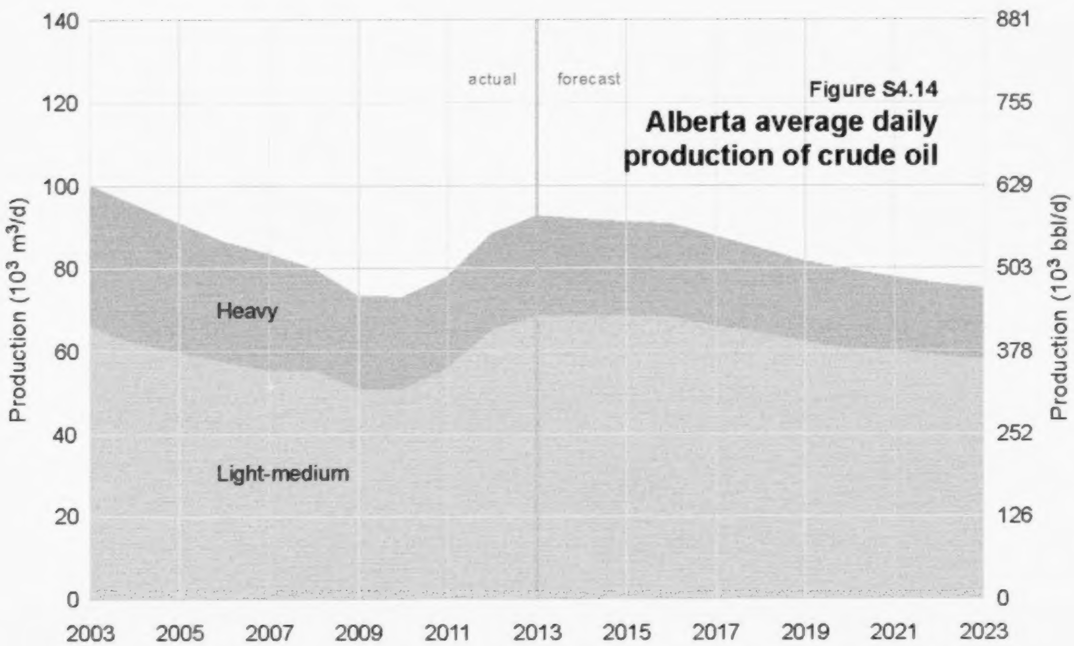


Figure S4.14
Alberta average daily production of crude oil

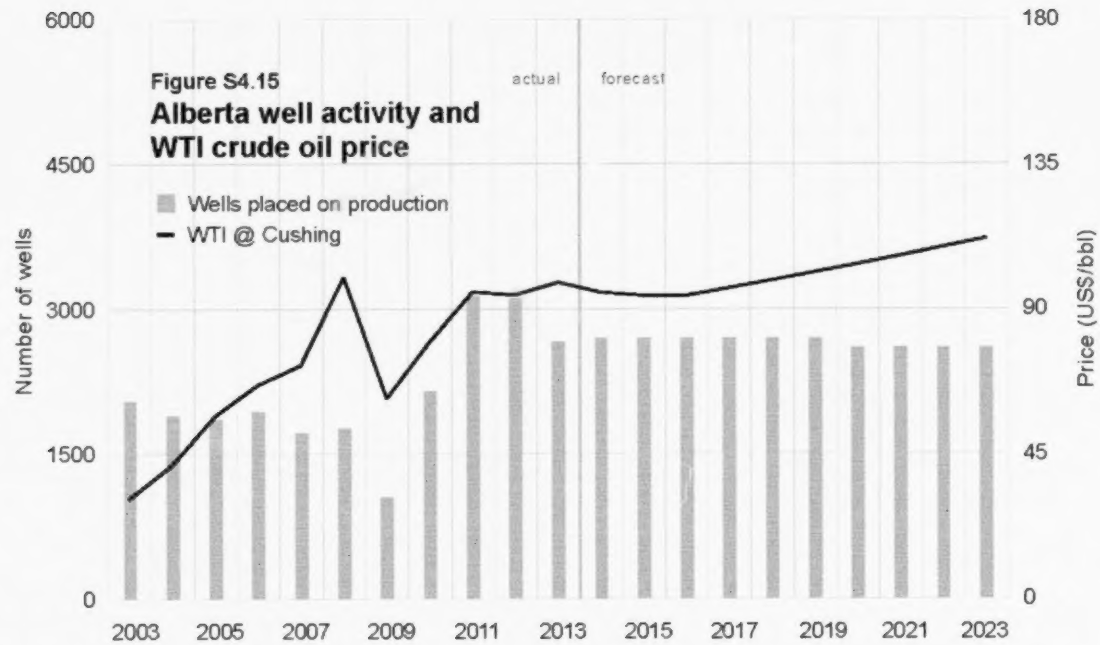


Figure S4.15
Alberta well activity and WTI crude oil price

forecast, oil drilling activity is expected to moderate, with an estimated 2600 wells placed on production at the end of the forecast period. Over the longer term, investment dollars are expected to be more evenly distributed between gas (with associated natural gas liquids) and oil drilling.

4.2.3 Crude Oil Demand

Oil refineries use mainly crude oil, butanes, and natural gas as feedstock, along with upgraded and nonupgraded bitumen and pentanes plus, to produce a wide variety of refined petroleum products (RPPs). The key determinants of crude oil feedstock requirements for Alberta's refineries are domestic Albertan demand for RPPs, shipments to other western Canadian provinces, exports to the United States, and competition from other feedstocks.

In 2013, Alberta's operating refineries, with a total inlet capacity of 72.7 10^3 m^3/d of crude oil and equivalent, processed 17.5 10^3 m^3/d of conventional crude oil. This is a 4 per cent increase in crude oil processed relative to 2012.

Both upgraded and nonupgraded bitumen, together with pentanes plus, constitute the remaining feedstock processed through Alberta's refineries. **Figure S4.16** illustrates the current capacity and location of refineries in Alberta. Additions to crude oil refining capacity are not expected over the forecast period.

In 2013, the refinery utilization capacity was about 93 per cent, up from 89 per cent in 2012 and 88 per cent in 2011. The forecast assumes that total crude oil use in Alberta's refineries will remain unchanged at 17.5 10^3 m^3/d in 2014 and continue to remain at this level for the remainder of the forecast period.

Shipments of crude oil outside of Alberta, depicted in **Figure S4.17**, amounted to 81 per cent of total production in 2013. The AER expects that by 2023, this figure will slowly decrease to about 77 per cent of production due to the decline expected in Alberta light-medium and heavy crude oil production in 2023. Currently, conventional crude oil removals are experiencing pipeline constraints and the issue is expected to continue in the near future. Also, light crude oil production from North Dakota and Texas offshore has been on the rise and could significantly affect Alberta crude oil demand in the United States towards the end of the forecast period.

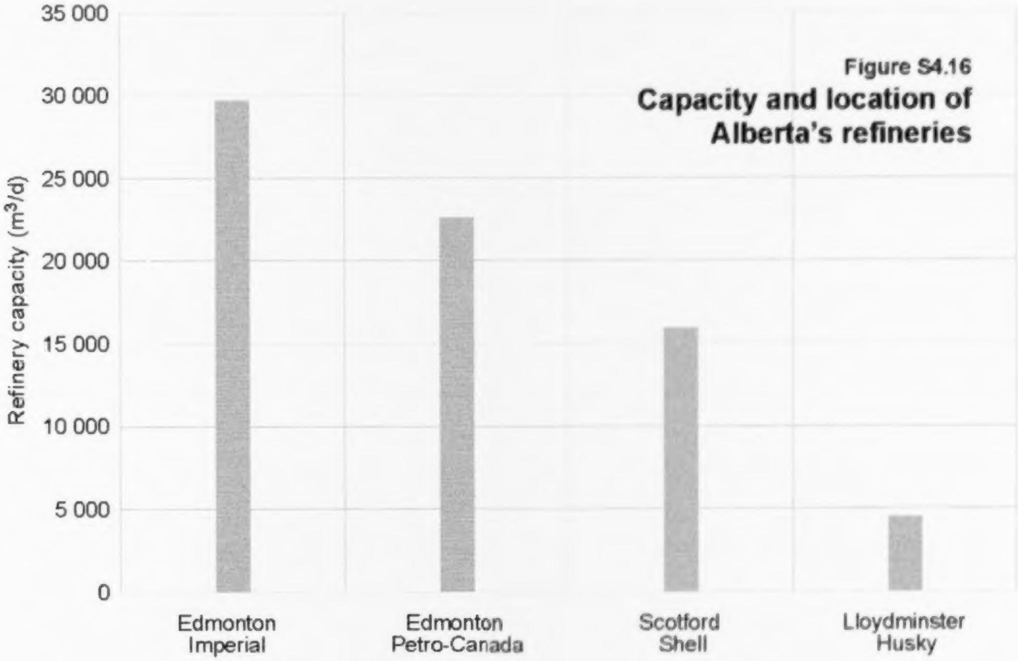


Figure S4.16
Capacity and location of Alberta's refineries

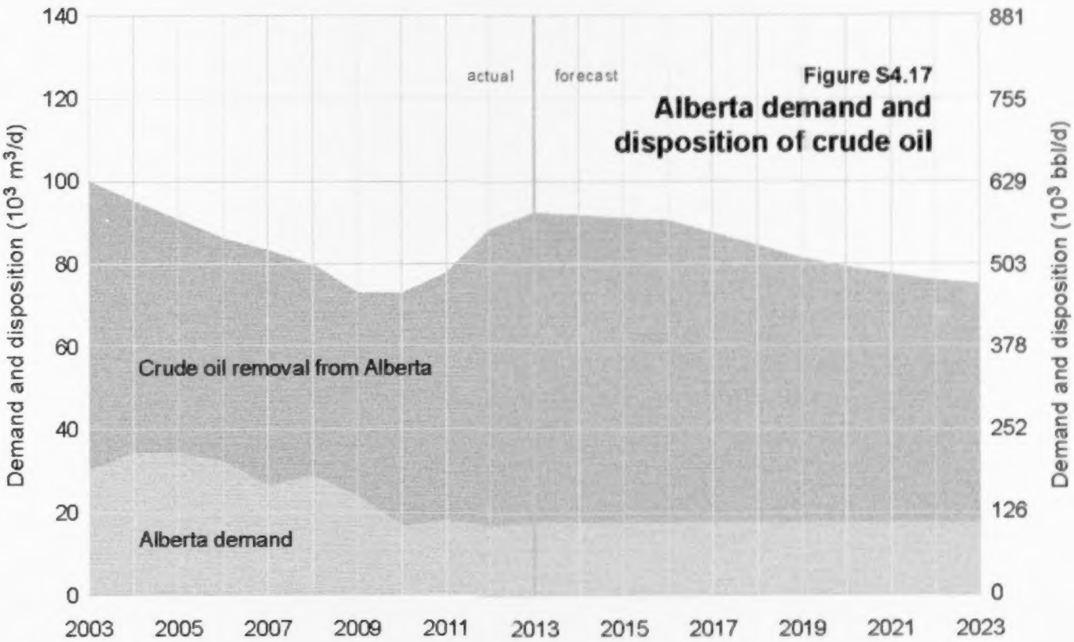


Figure S4.17
Alberta demand and disposition of crude oil

5 NATURAL GAS

Raw natural gas consists mostly of methane and other hydrocarbon gases, but it also contains nonhydrocarbons, such as nitrogen, carbon dioxide, and hydrogen sulphide (H_2S). These impurities typically make up less than 10 per cent of raw natural gas. The estimated average composition of the hydrocarbon component without impurities is about 92 per cent methane, 5 per cent ethane, and lesser amounts of propane, butanes, and pentanes plus.

The range of hydrocarbon gas components in Alberta's natural gas covers a wide spectrum, from dry gas to liquids-rich gas. Dry gas generally consists of mostly methane with some examples being shallow gas pools located in southeast Alberta and coalbed methane (CBM) deposits in central Alberta. Gas with small amounts of extractable liquids is referred to as lean gas, whereas gas with larger amounts is called wet gas. Liquids-rich gas refers to natural gas that contains an unusually high amount of liquids. Pools containing liquids-rich gas are often found along the front of the foothills of the province.

Hydrocarbon components that exist in gaseous form in the reservoir but which condense and are recovered as a liquid at the surface may be reported as gas equivalent or condensate. Such liquids—including ethane, which is primarily produced as a gas—are referred to as natural gas liquids (NGLs) and are reported in **Section 6**. Marketable gas is the gas that remains after the raw gas is processed to remove nonhydrocarbons and heavier natural gas liquids and that meets specifications for use as a fuel. Marketable gas reserves are determined by applying a surface loss or shrinkage factor to the raw gas volume and are described in **Section 5.1.3.5**.

In this section, natural gas volumes are referred to as either the actual metered volume with the combined heating value of the hydrocarbon components present in the gas (i.e., "as is") or the volume at standard conditions of 37.4 megajoules per cubic metre (MJ/m^3). The average heat content of produced conventional natural gas leaving field plants is estimated to be 39.2 MJ/m^3. This compares with a heat content of about 37.0 MJ/m^3 for CBM.

This section discusses conventional and unconventional natural gas, with unconventional gas defined as being CBM and shale gas.

HIGHLIGHTS

Alberta's remaining established conventional natural gas reserves decreased by 2 per cent in 2013 to 898 billion cubic metres.

Additions to reserves due to new drilling replaced 36 per cent of conventional gas production.

Marketable gas production declined by 3 per cent in 2013, compared with a 6 per cent decline in 2012.

There were 1019 conventional gas well placed on production, 130 coalbed methane (CBM) and CBM hybrid producing wells, and 23 shale gas wells placed on production in 2013, down 14 per cent and 70 per cent, and up 109 per cent, respectively, from 2012.

5.1 Reserves of Natural Gas

5.1.1 Provincial Summary

As of December 31, 2013, the AER estimates the remaining established reserves of marketable conventional gas in Alberta downstream of field plants to be 898 billion (10^9) m^3, with a total energy content of about 35 exajoules (10^{18} joules). This decrease of 18.2 10^9 m^3 since December 31, 2012, is a result of all reserves additions less production during 2013. These reserves include 29.6 10^9 m^3 of ethane and other NGLs, which are present in marketable gas leaving the field plant and are subsequently recovered at straddle plants. Removal of NGLs results in a 4.6 per cent reduction in the average heating value, from 39.2 MJ/m^3 to 37.4 MJ/m^3, for gas downstream of straddle plants. Details of the changes in marketable reserves during 2013 are shown in **Table R5.1**. Total provincial initial gas in-place and raw producible gas reserves for 2013 were 9397.7 and 6271.8 10^9 m^3, respectively, which translates into an average provincial recovery factor of 67 per cent. Total initial established marketable reserves were estimated to be 5420.6 10^9 m^3, representing an average surface loss of 14 per cent.

Annual historical reserves additions and natural gas production are depicted in **Figure R5.1**. It shows that since 1983, reserves additions have generally not kept pace with production. As illustrated in **Figure R5.2**, Alberta's remaining established reserves of marketable conventional gas have decreased by about 51 per cent since 1983.

The AER estimates the initial established reserves of CBM to be 101.7 10^9 m^3 as of December 31, 2013, relatively unchanged from 2012. Remaining established reserves in 2013 were 51.5 10^9 m^3, down from 56.7 10^9 m^3 in 2012 due to production.

Table R5.1 Reserve and production changes in marketable conventional gas (10^9 m^3)

	Gross heating value (MJ/m^3)	Volumes 2013	Volumes 2012	Change
Initial established reserves		5 420.6	5 341.1	+79.5
Cumulative production		4 523.0	4 425.4	+97.6[a]
Remaining established reserves downstream of field plants				
As is	39.2	897.5	915.7	-18.2
At standard gross heating value	37.4	941.0	957.2	
Minus liquids removed at straddle plants		29.6	28.9	0.7[b]
Remaining established reserves				
As is	37.4	867.9[b]	886.7[b]	-18.8[b]
		(30.8 Tcf)[c]	(31.5 Tcf)[c]	
At standard gross heating value	37.4	867.3	885.2	
Annual production	37.4	94.4[d]	97.1[d]	-2.6[d]

[a] Change in cumulative production is a combination of annual production and all adjustments to previous production records.
[b] Any discrepancies are due to rounding.
[c] Tcf = trillion cubic feet.
[d] Does not include conventional gas from AER-defined unconventional wells.

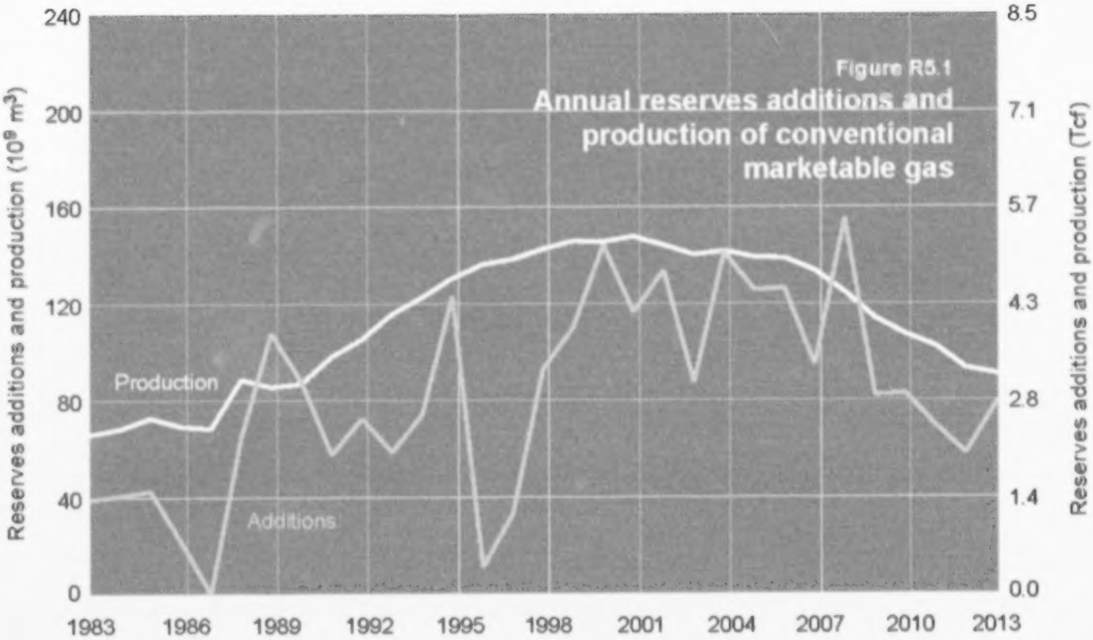


Figure R5.1
Annual reserves additions and production of conventional marketable gas
Production
Additions
Reserves additions and production (10^9 m^3)
Reserves additions and production (Tcf)
240
200
160
120
80
40
0
8.5
7.1
5.7
4.3
2.8
1.4
0.0
1983
1986
1989
1992
1995
1998
2001
2004
2007
2010
2013

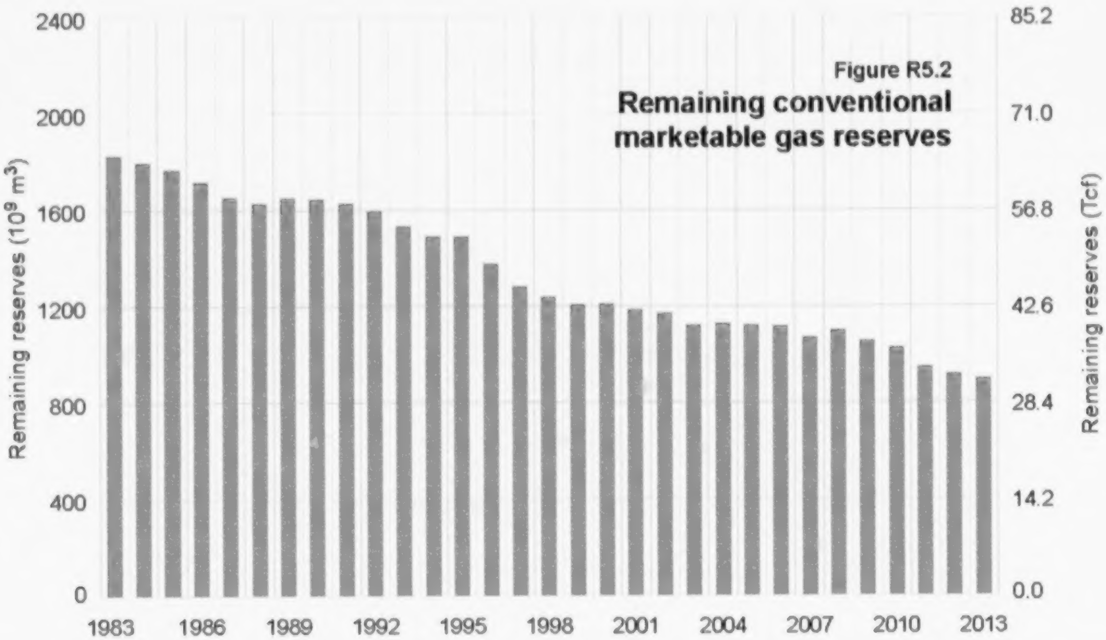


Figure R5.2
Remaining conventional marketable gas reserves
Remaining reserves (10^9 m^3)
Remaining reserves (Tcf)
2400
2000
1600
1200
800
400
0
85.2
71.0
56.8
42.6
28.4
14.2
0.0
1983
1986
1989
1992
1995
1998
2001
2004
2007
2010
2013

Table R5.2 CBM reserve and production change highlights (10^9 m^3)

	2013	2012	Change
Initial established reserves	101.7	101.3	+0.5
Cumulative production	50.2	44.5	+5.7[a]
Remaining established reserves	51.5	56.7	-5.3
	(1.8 Tcf)[b]	(2.0 Tcf)[b]	
Annual production	5.2	5.6	-0.4

[a] Change in cumulative production is a combination of annual production and all adjustments to previous production records.
[b] Tcf = trillion cubic feet.

A summary of CBM reserves and production is shown in **Table R5.2**. In 2013, the annual production from all wells listed as CBM was 7.6 10^9 m^3. This volume represents the total contribution from CBM wells, including wells commingled with conventional gas.[1] The portion of production estimated to be attributed to only CBM is 5.2 10^9 m^3.

5.1.2 In-Place Resources

The AER estimates the initial in-place resources of conventional and CBM natural gas in Alberta to be 9699 10^9 m^3, consisting of 9398 10^9 m^3 of conventional natural gas and 301 10^9 m^3 of CBM. With conventional cumulative raw production of 5275 10^9 m^3, 4123 10^9 m^3 of this gas remains in the ground. CBM cumulative raw production is 50 10^9 m^3, and 251 10^9 m^3 of CBM remains in the ground. As of December 31, 2013, 4374 10^9 m^3 of natural gas remains unproduced in Alberta. With current technologies, 1048 10^9 m^3 is still expected to be produced.

Additionally, the shale- and siltstone-hosted hydrocarbon resources study discussed in **Section 2.2.2** has identified 95 944 10^9 m^3 (3406 trillion cubic feet [Tcf]) of unconventional in-place shale gas resources in six key shale formations in Alberta. This very large resource represents a huge potential for future development; however, the technical, economic, environmental, and social constraints on recoverability were not studied in the report. Consequently, the AER has not determined any established reserves from this resource.

5.1.3 Established Reserves of Conventional Natural Gas

Figure R5.3 breaks down the historical annual reserves changes according to new pools, development of existing pools, and reassessment of reserves of existing pools. The 79.5 10^9 m^3 increase in initial reserves for 2013 includes the addition of 20.9 10^9 m^3 attributed to new pools booked in 2013, 12.4 10^9 m^3 from the development of existing pools, and a net reassessment of 46.2 10^9 m^3 for existing pools. Reserves added through drilling (new plus development) totalled 33.3 10^9 m^3, replacing 36 per cent of Alberta's 2013 production. This is up from 25 per cent in 2012, which was the lowest replacement ratio in the last 15 years. Historical reserves growth and production data since 1966 are shown in **Appendix B, Table B.4**.

[1] Wells commingled with conventional gas are defined as CBM hybrid wells.

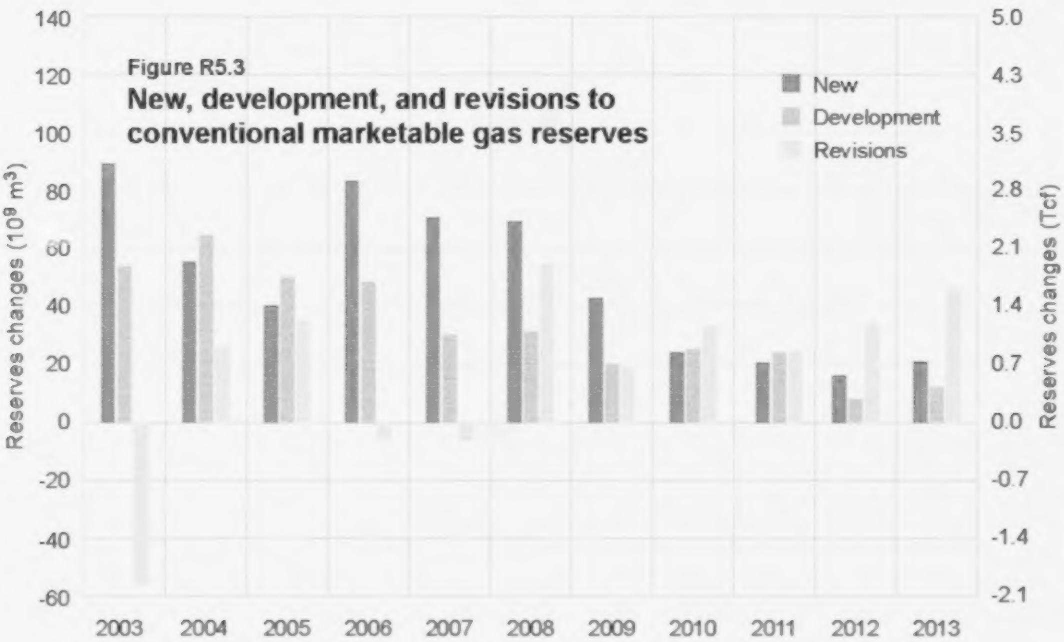


Figure R5.3
New, development, and revisions to conventional marketable gas reserves

During 2013, a review was done of pools that appeared to have reserves under- or overbooked based on their reserves-to-production ratios; another review was done of large pools that had not been evaluated for several years. Positive revisions to existing pools totalled 89 10^9 m^3, while negative revisions totalled 54 10^9 m^3. Despite the low number of wells being drilled in southeast Alberta, this area still contributes significant volumes of gas to the provincial total. The review of shallow gas pools within the southeastern Alberta gas system resulted in a decrease in reserves of 14.5 10^9 m^3. About 2900 pools throughout Alberta were evaluated with low or high reserve life indices, resulting in an overall decrease in reserves of 1.4 10^9 m^3. Previous editions of this report have included a table listing the natural gas pools with the largest changes. With the ever increasing number of commingled gas pools in Alberta, it is becoming more difficult to quantify whether these changes to reserves are, in fact, an increase in reserves or simply the result of summing multiple reserves due to commingling.

Figure R5.4 illustrates initial marketable gas reserves growth between 2012 and 2013 by areas defined by the Petroleum Services Association of Canada (PSAC). The most significant growth was in PSAC Area 2, which accounted for 70 per cent of the total annual increase for 2013. Among the pools in PSAC Area 2 that contributed to this increase in reserves were the Ferrier Commingled Pool 002, Kakwa Commingled Pool 005, Pembina Commingled MFP9537, Smoky Commingled Pool 017, and Wapiti Commingled MFP 9529, for a total reserves increase of 16.5 10^9 m^3.

5.1.3.1 Distribution of Conventional Natural Gas Reserves by Pool Size

The distribution of marketable gas reserves by pool size is shown in **Table R5.3**. Commingled pools are considered as one pool, whereas each pool in a multifield pool is counted as a separate pool. The data show that pools with reserves of less than 30 million (10^6) m^3, while representing 76 per cent of all pools, contain

Figure R5.4
Initial marketable conventional gas reserves changes by PSAC area (10^9 m^3)

2012
Total = 58.0 10^9 m^3

2013
Total = 79.5 10^9 m^3

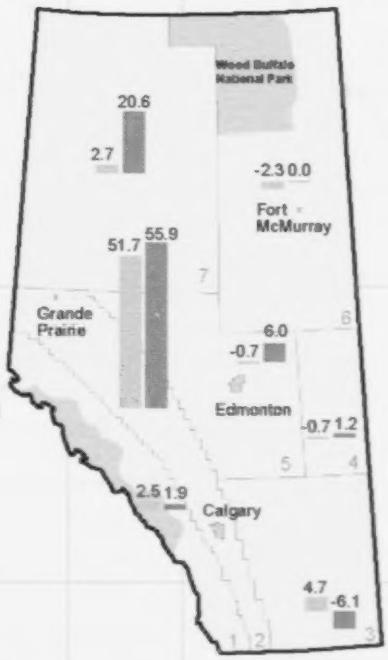
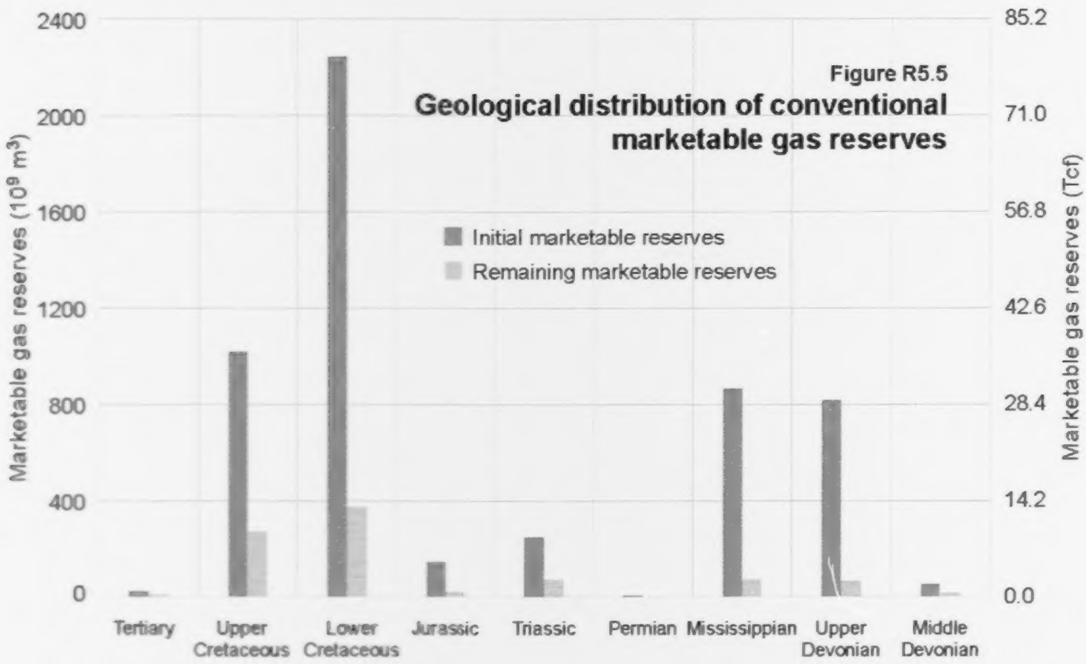


Table R5.3 Distribution of natural gas reserves by pool size, 2013

Reserve range (10^6 m^3)	Pools		Initial established marketable reserves		Remaining established marketable reserves	
	#	%	10^9 m^3	%	10^9 m^3	%
3000+	232	0.5	3 062	56	481	54
1501–3000	172	0.4	361	7	60	7
1001–1500	191	0.4	236	4	37	4
501–1000	533	1.1	369	7	45	5
101–500	3 408	7.0	711	13	105	12
30–100	7 264	15.0	388	7	77	9
Less than 30	36 551	75.6	294	5	93	10
Total	**48 351**	**100.0**	**5 421**	**100**	**898**	**100**



only 10 per cent of the province's remaining marketable reserves. Similarly, pools with reserves greater than 3000 10^6 m^3, while representing only 0.5 per cent of all pools, contain 54 per cent of the remaining reserves.

5.1.3.2 Geological Distribution of Conventional Natural Gas Reserves

The distribution of reserves by geological period is shown in **Figure R5.5**. The Upper and Lower Cretaceous periods account for about 72 per cent of the province's remaining established reserves of marketable gas and is important as a future source of natural gas.

The geological strata containing the largest remaining reserves are the Lower Cretaceous Mannville, Glauconitic, Ellerslie, and Viking, with 35 per cent; the Upper Cretaceous Cardium, Belly River, Milk River, and Medicine Hat, with 22 per cent; and the Mississippian Rundle, with 7 per cent. Together, these strata contain 64 per cent of the province's remaining established marketable gas reserves.

5.1.3.3 Gas Commingling

Gas commingling is the unsegregated production of gas from more than one pool in a wellbore. As shown in **Table R5.4**, 27 per cent (16 351) of all gas pools in Alberta are commingled. This represents 554 10^9 m^3, about 62 per cent of remaining established reserves. In comparison, commingled pools represented only 33 per cent of remaining reserves in 2001.

Table R5.4 Pool reserves as of December 31, 2013 (10^9 m^3)

	Number of commingled pools	Number of individual pools	Initial established reserves	Cumulative production	Remaining established reserves
Commingled pools	4 237	16 351	2 928	2 374	554
Noncommingled pools		44 114	2 493	2 149	344
Total			**5 421**	**4 523**	**898**

Table R5.5 Commingled pool reserves within development entities as of December 31, 2013 (10^9 m^3)

	Number of commingled pools	Number of individual pools	Initial established reserves	Cumulative production	Remaining established reserves
DE No. 1	697	2 194	397	336	61
DE No. 2	731	4 104	894	666	228
Total	**1 428**	**6 298**	**1 291**	**1 002**	**289**

In 2006, the AER issued orders establishing two development entities (DEs No. 1 and 2)[2] that allow for the commingling of gas from certain formations within these areas without an application to the AER. Subsequently, the AER amended the area described as DE No. 2 in 2010. The commingling of gas from certain formations within these areas has enabled operators to produce reserves from zones that otherwise would have been uneconomic to produce on their own.

Table R5.5 shows that DEs No. 1 and 2 have remaining established reserves of 61 10^9 m^3 and 228 10^9 m^3, respectively. The commingled gas reserves of DEs No. 1 and 2 account for about 32 per cent of Alberta's remaining established reserves.

5.1.3.4 Reserves of Conventional Natural Gas Containing Hydrogen Sulphide

Hydrogen sulphide (H_2S) is a naturally occurring substance present in many oil and gas reservoirs worldwide. Natural gas that contains more than 0.01 per cent H_2S is referred to as sour in this report.

In oil and gas reservoirs, H_2S is primarily generated through thermal and biological processes, both of which involve a reaction between dissolved sulphates and hydrocarbons. Thermally generated H_2S produces the highest concentrations of H_2S and occurs in reservoirs that have undergone diagenesis due to deep burial. Biologically generated H_2S is commonly found in shallower, lower temperature reservoirs, but can also occur in sewers, swamps, composts, and manure piles.

In Alberta, sour gas is found in several regions and formations across the province. The maps in **Figure R5.6** and **Figure R5.7** show the distribution of both 2013 and historical development of H_2S-bearing hydrocarbons

[2] A DE is a specified area consisting of multiple formations from which gas may be produced without segregation in the wellbore. These areas are described in AER orders DE 2006-1 and DE 2006-2 and are subject to certain criteria in the *Oil and Gas Conservation Rules*, section 3.051.

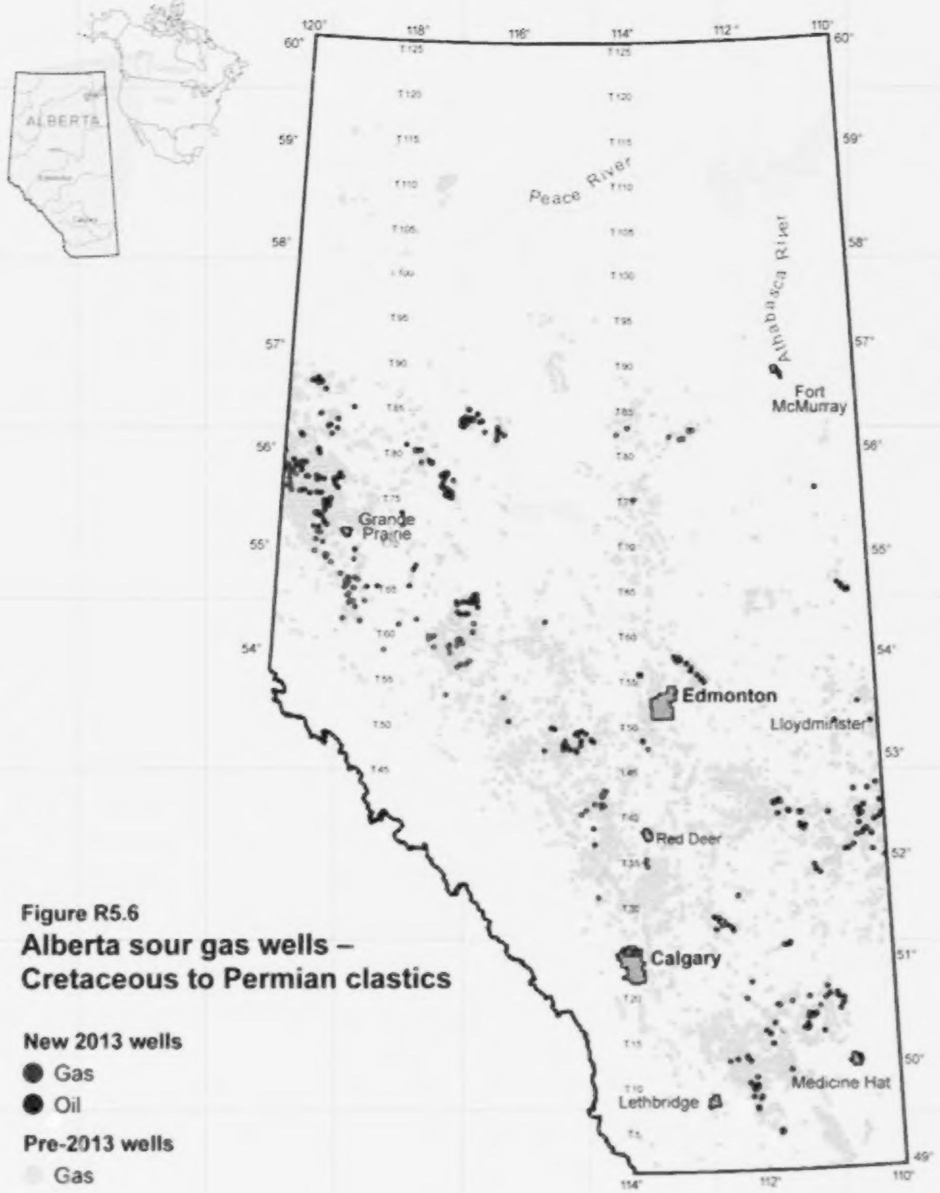


Figure R5.6
Alberta sour gas wells – Cretaceous to Permian clastics

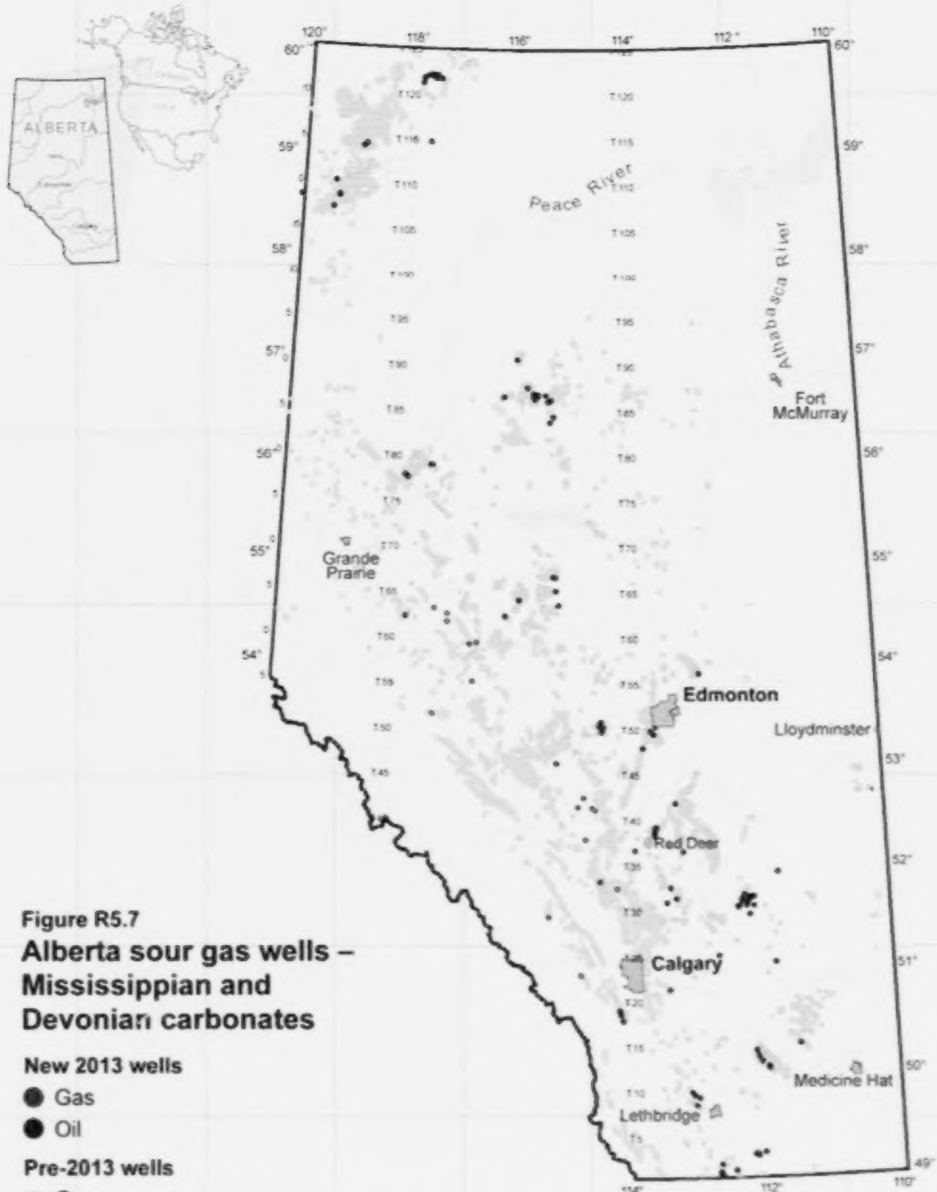


Figure R5.7
Alberta sour gas wells – Mississippian and Devonian carbonates

New 2013 wells
- Gas
- Oil

Pre-2013 wells
- Gas
- Oil

within the clastic and carbonate successions of the Western Canada Sedimentary Basin (WCSB). The division of these two maps reflects Alberta's basin architecture, which consists of a Cretaceous- to Permian-aged clastic wedge overlying a primarily Mississippian- and Devonian-aged carbonate succession (as discussed previously in **Section 2.1**).

The highlighted 2013 sour gas wells on the maps in **Figure R5.6** and **Figure R5.7** shows areas of new sour gas development contrasted against historical drilling. As shown by these maps, much of the new H_2S-bearing hydrocarbon development in the province resulted from the drilling of oil wells.

Prominent sour gas production for 2013 included the Triassic-focused activity in the northwest, the development of Lower Cretaceous- and Jurassic-aged strata east of the foothills, and Cretaceous-aged enhanced oil recovery near the Saskatchewan border (**Figure R5.6**). Sour development within the carbonate-dominated strata (**Figure R5.7**) was focused on the oil-rich Devonian and Mississippian strata of the central and eastern plains.

As of December 31, 2013, sour gas accounted for about 22 per cent (201 10^9 m^3) of the province's total remaining established gas reserves and about 19 per cent of raw natural gas production in 2013. The average H_2S concentration of initial producible reserves of sour gas in the province at year-end 2013 was 8.2 per cent.

The distribution of reserves of sweet and sour gas provided in **Table R5.6** shows that 117 10^9 m^3, or about 59 per cent, of remaining sour gas reserves are in nonassociated pools. Since 2002, sour gas has consistently accounted for about 20 per cent of the total remaining marketable reserves. The distribution of sour gas reserves by H_2S content, shown in **Table R5.7**, indicates that 14 per cent (26 10^9 m^3) of remaining sour gas contains H_2S concentrations greater than 10 per cent, while 61 per cent (121 10^9 m^3) contains concentrations less than 2 per cent.

Table R5.6 Distribution of sweet and sour gas reserves, 2013

	Marketable gas (10^9 m^3)			Percentage	
Type of gas	**Initial established reserves**	**Cumulative production**	**Remaining established reserves**	**Initial established reserves**	**Remaining established reserves**
Sweet					
Associated and solution	892	705	187	16	21
Nonassociated	2 749	2 239	510	51	57
Subtotal	**3 641**	**2 944**	**697**	**67**	**78**
Sour					
Associated and solution	564	481	83	10	9
Nonassociated	1 215	1 098	117	22	13
Subtotal	**1 779**	**1 579**	**200**	**33**	**22**
Total	**5 420**	**4 523**	**897**[a]	**100**	**100**
	(192 Tcf)[b]	**(161 Tcf)**[b]	**(31.8 Tcf)**[b]		

[a] Reserves estimated at field plants.

[b] Tcf = trillion cubic feet.

Table R5.7 Distribution of sour gas reserves by H_2S content, 2013

	Initial established reserves (10^9 m^3)		Remaining established reserves (10^9 m^3)			
H_2S content in raw gas (%)	Associated and solution	Nonassociated	Associated and solution	Nonassociated	Total	%
Less than 2	419	449	66	56	**122**	61
2–10	102	403	12	40	**52**	26
10–20	32	210	4	11	**15**	8
20–30	11	49	1	4	**5**	3
Over 30	0	104	0	6	**6**	3
Total[a]	**564**	**1215**	**83**	**117**	**200**	**100**
Percentage	32	69	42	59		

[a] Any discrepancies are due to rounding.

5.1.3.5 Reserves Methodology for Conventional Natural Gas

A detailed pool-by-pool list of reservoir parameters and reserves data for all conventional oil and gas pools is on CD (see **Appendix C**) and is available from the AER's Order Fulfillment Team.

The process of determining reserves takes into consideration geological, engineering, and economic factors. Though initial estimates contain a level of uncertainty, this level of uncertainty decreases over the life of the pool as more information becomes available and actual production is observed and analyzed. The initial reserves estimates are normally based on volumetric calculations that use bulk rock volume (based on isopach maps derived from geological interpretation of well log data) and initial reservoir parameters to estimate gas in-place at reservoir conditions. Drainage areas for single-well pools range from 200 hectares (ha) for regional sands with good permeability to 32 ha or less for low-permeability formations or geological structures limited in areal extent.

Converting gas volume in-place to specified standard conditions at the surface requires knowledge of reservoir pressure, temperature, and gas content. A recovery factor is applied to the in-place volume to yield the recoverable reserves—the volume that will actually be produced to the surface. Given the low viscosity and high mobility of natural gas, recoveries typically range from 70 to 90 per cent. However, low-permeability gas reservoirs and reservoirs with underlying water may only recover 50 per cent or less of the in-place volume.

Once a pool has been on production for some time, a material balance analysis involving the decline in pool pressure can be used as an alternative to the volumetric estimation to determine in-place resources. Material balances are more accurate when applied to high-permeability, nonassociated, and noncommingled gas pools. An analysis of production decline data is the primary method of determining recoverable reserves, given that most of the larger pools in the province have been in decline for many years. When combined with an estimate of the in-place resources, it also provides a practical, realistic estimate of the pool's recovery factor.

The procedures described above generate an estimate of the initial established reserves of raw gas. The raw natural gas reserves must be converted to a marketable volume (i.e., the volume that meets pipeline specifications) by applying a surface loss or shrinkage factor. Based on the gas analysis for each pool, a surface

loss is estimated using an algorithm that reflects expected recovery of liquids (ethane, propane, butanes, and pentanes plus) at field plants. Typically, 5 per cent is added to account for loss due to lease fuel (estimated at 4 per cent) and flaring. Surface losses range from 3 per cent for pools containing sweet dry gas to over 30 per cent for pools with raw gas containing high concentrations of H_2S and gas liquids. Therefore, marketable gas reserves of individual pools in the AER's gas reserves database reflect expected marketable reserves after processing at field plants. The pool reserve numbers published by the AER represent estimates for in-place resources, recoverable reserves, and associated recovery factors based on the most reasonable interpretation of available information from volumetric, production decline, and material balance estimates.

Additional liquids contained in the gas stream leaving the field plants are extracted downstream at straddle plants. Exceptions to this are the gas shipped to Chicago through the Alliance pipeline and some of the dry southeastern Alberta gas. As removal of these liquids cannot be traced back to individual pools, a gross adjustment for the liquids is made to arrive at the estimate for remaining reserves of marketable gas for the province. These provincial reserves, therefore, represent the volume and average heat content of gas after the removal of liquids from both field and straddle plants.

It is expected that about 29.6 10^9 m^3 of liquids-rich gas will be extracted at straddle plants, thereby reducing the remaining established reserves of marketable gas (estimated at the field plant gate) from 897.5 10^9 m^3 to 867.9 10^9 m^3 and the total thermal energy content from 35.2 to 32.4 exajoules.

Figure R5.8 shows the average percentage of remaining established reserves of each hydrocarbon component expected to be extracted at field and straddle plants. For example, of the total ethane content in raw natural gas, about 25 per cent is expected to be removed at field plants and an additional 40 per cent at straddle plants.

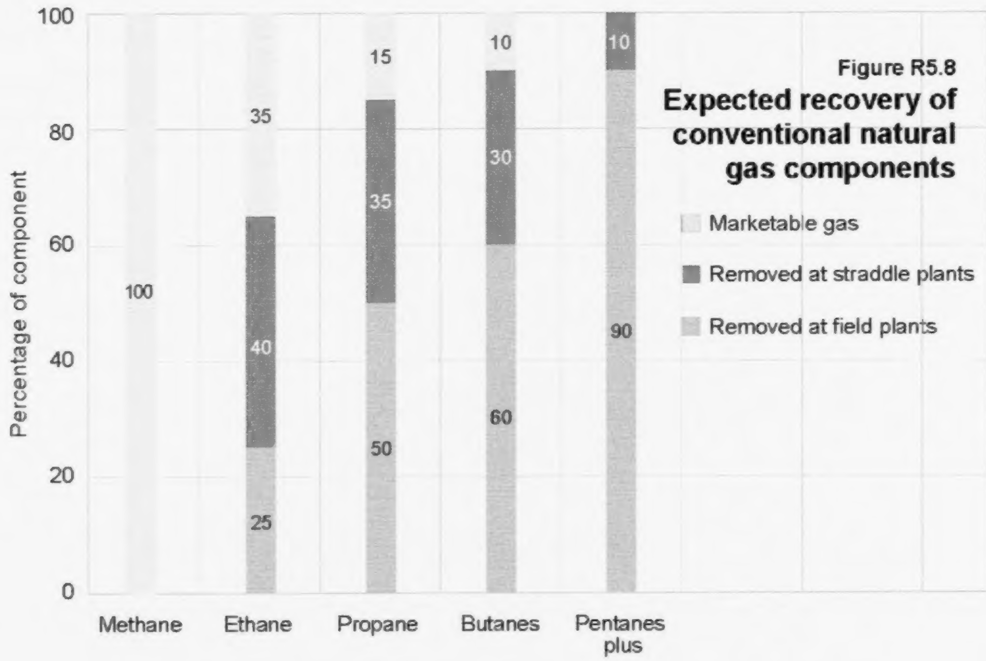


Figure R5.8
Expected recovery of conventional natural gas components

Therefore, the AER estimates the reserves of liquid ethane that will be extracted based on 65 per cent of the total raw ethane gas reserves. The remaining 35 per cent of the ethane is left in the marketable gas and sold for its heating value. This ethane represents a potential source of future ethane supply.

Reserves of NGLs are discussed in more detail in **Section 6**.

5.1.3.6 Multifield Pools

Pools that extend over more than one field are classified as multifield pools and are listed in **Table B.5** in **Appendix B**. For each multifield pool, the individual remaining established reserves assigned to each field and the total remaining established reserves for the multifield pool are shown.

5.1.4 Established Reserves of CBM

CBM is the methane gas found in coal, both as adsorbed gas and as free gas. Unlike conventional gas, which occurs as discrete accumulations, or pools, CBM most often occurs in interconnected coal seams within defined stratigraphic zones as laterally continuous accumulations or deposits.

CBM may contain small amounts of carbon dioxide and nitrogen (usually less than 5 per cent). H_2S is not normally associated with CBM production as the coal adsorption coefficient for H_2S is far greater than for methane. The heating value of CBM is generally about 37 MJ/m^3.

5.1.4.1 CBM Potential by Geological Strata

Based on the analysis of thousands of coalholes and oil and gas wells, coal is known to underlie most of central and southern Alberta—one of the largest geographical extents of continuous coal in North America. Coal seams occur as layers or beds within several Cretaceous coal zones. While individual coal seams can be laterally discontinuous, coal zones can be correlated very well over regional distances. All coal seams contain CBM to some extent, and each seam is potentially capable of producing CBM.

The AER recognizes CBM reserves in the following horizons of Alberta:

- **Coals of the Horseshoe Canyon Formation and Belly River Group** – Horseshoe Canyon coals generally have low gas content and low water volume, with production referred to as "dry CBM." The first commercial production of CBM in Alberta was from these coals, and they constitute most of the CBM reserves booked. Reserves from the Taber or MacKay coal zones of the Belly River Group have not yet been established.
- **Coals of the Mannville Group** – Mannville coals generally have high gas content and high volume of saline water, requiring extensive pumping and water disposal. The initial reserves for areas other than the Corbett area within the Mannville Group have been set at cumulative production.

The Ardley coals of the Scollard Formation and the Kootenay coals of the Mist Mountain Formation also show potential for production, but at this time no CBM reserves have been calculated for these coals.

An individual CBM zone is defined as all coal seams within a formation separated by less than 30 m of non-coal-bearing strata or separated by a previously defined conventional gas pool. Several individual producing coal seams in one CBM zone are considered to be one CBM pool for regulatory and administrative purposes. For administrative purposes, previous pools limited by field boundaries have been converted to multifield CBM pools. However, as multifield pools are still problematic in grouping CBM resource and reserve estimates, the AER groups CBM volumes into deposit-based play areas.

5.1.4.2 CBM Deposits, Play Areas, and Play Subareas

Although CBM is regulated and administered as if it existed in pools, CBM accumulations exist more as deposits. The AER assesses CBM deposits for reserve determination in a manner similar to the way it assesses oil sands deposits. CBM deposits are stratigraphic intervals that extend over a large geographic area and may include one or more CBM zones. Unlike oil sands deposits, however, the AER has yet to formally define CBM deposits because it is still monitoring development activities. Currently, CBM deposits are informally based on formations, with the two main CBM deposits being the Horseshoe Canyon and the Mannville. Within each of these deposits, development activities have, until now, been concentrated mainly in a single smaller play area.

While Mannville activity is clustered almost exclusively in the Corbett area, the more widespread Horseshoe Canyon play occurs over a large area in central Alberta between Calgary and Edmonton. Currently, the Horseshoe Canyon play area is within the AER-designated DE No. 1 and the southeastern Alberta gas system. The current play areas for the Horseshoe Canyon and Mannville deposits are shown in **Figure R5.9**.

Although coal zones are regionally extensive, the values of reservoir parameters used for reserves estimates are determined locally. As a result, for reserves estimation and reporting purposes, the large central Alberta play area of the Horseshoe Canyon deposit is divided into subareas based on reservoir and production profile differences defined by data from control wells within the deposit. The location of the Horseshoe Canyon play subareas is also shown on **Figure R5.9**.

5.1.4.3 CBM Reserves Determination Method

The AER uses three-dimensional block models to estimate in-place CBM resources for each play area or subarea. Desorption data are used on a zonal basis by applying gas content trends from core to all coals in each zone to estimate in-place CBM resources. Desorption values from drill cuttings are used to validate the continuity of the zonal trends from core.

Current reserve estimates are determined by applying an average recovery factor based on analysis of control well data for each play subarea. These recovery factors are shown for each subarea in **Table R5.8**. The method of determining reserves depends on flowmeter values and changes in reservoir pressure as determined by qualitatively comparing annual measurements in each CBM zone. If the data or production reporting is missing, then the result is assumed to be zero. Future analysis is expected to improve estimates of recovery factors. CBM data are available on two systems from the AER: the integrated geological database (summarized net pay data) and the coalhole database (individual coal seam thickness picks).

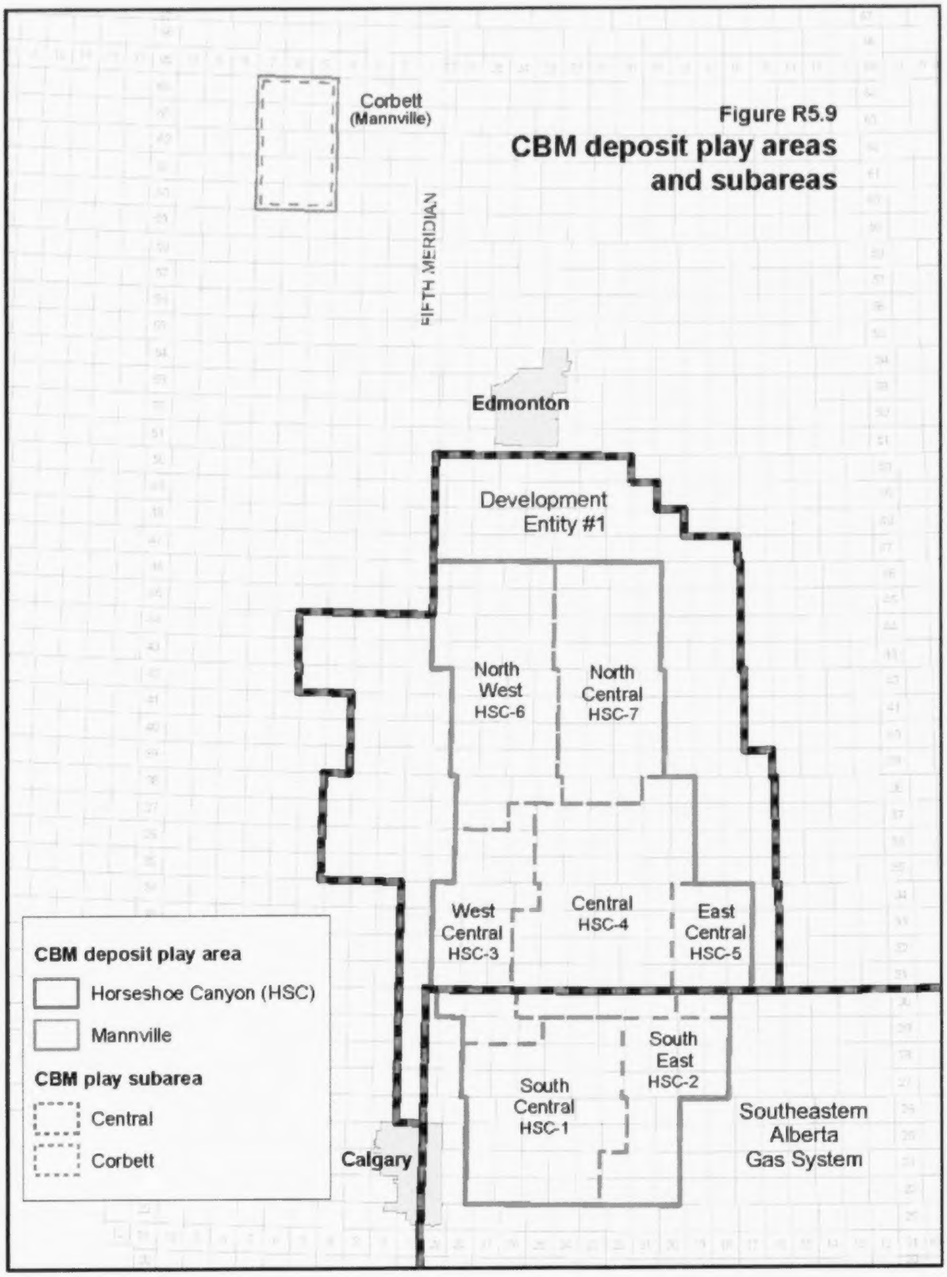


Figure R5.9
CBM deposit play areas and subareas
Corbett (Mannville)
FIFTH MERIDIAN
Edmonton
Development Entity #1
North West HSC-6
North Central HSC-7
West Central HSC-3
Central HSC-4
East Central HSC-5
South East HSC-2
South Central HSC-1
Southeastern Alberta Gas System
Calgary
CBM deposit play area
Horseshoe Canyon (HSC)
Mannville
CBM play subarea
Central
Corbett

Table R5.8 CBM gas in-place and reserves by deposit play area, 2013

Deposit and play subareas	Average net coal thickness (m)	Coal reservoir volume (10^9 m^3)	Estimated gas content (m^3 gas/ m^3 coal)	Initial gas in-place (10^9 m^3)	Average recovery factor (%)	Initial established reserves (10^9 m^3)	Cumulative production (10^9 m^3)	Remaining established reserves (10^9 m^3)
Horseshoe Canyon[a]								
HSC-1	10.1	35.37	2.95	104.38	27	28.56	7.80	20.76
HSC-2	4.3	9.04	1.06	9.61	25	2.37	0.59	1.78
HSC-3	5.8	13.91	2.41	33.56	30	10.19	5.43	4.76
HSC-4	6.4	28.39	1.72	48.84	34	16.47	14.41	2.06
HSC-5	3.0	3.93	1.11	4.37	26	1.13	0.83	0.30
HSC-6	3.5	8.67	1.57	13.58	30	4.14	3.99	0.15
HSC-7	4.4	14.74	1.30	19.19	32	8.31	8.28	0.03
Undefined[b]	-	-	-	-	-	1.70	1.70	0.00
Subtotal	**5.4**[c]	**114.05**	**2.05**[c]	**233.53**	**31**[c]	**72.87**	**43.03**	**29.84**
Mannville								
Corbett	4.9	6.97	9.73	67.86	42	28.18	6.53	21.65
Undefined[b]	-	-	-	-	-	0.68	0.68	0.00
Total		**121.02**		**301.39**	**33**[c]	**101.73**	**50.24**	**51.49**

[a] Includes Upper Belly River CBM.

[b] Most of the undefined areas are for tests in the Mannville coals, but include a few Horseshoe Canyon, Ardley, and Kootenay wells with minor production and many Belly River recent recompletions with incomplete reporting.

[c] Weighted average.

5.1.4.4 Detail of CBM Reserves and Well Performance

CBM initial established reserve values remain generally unchanged from 2012. The AER is currently reviewing the reserves determination process for CBM in Alberta.

Horseshoe Canyon coals, which are mainly gas charged, with little or no pumping of water required, remain the main focus of industry and currently have the highest established reserves (see **Table R5.8**). New data have supported including additional areas within many of the Horseshoe Canyon CBM play subareas. In subarea 1, coals are deeper and have higher gas content, making this area one of the largest initial established reserves of CBM in the Horseshoe Canyon play.

The row labelled "undefined" in **Table R5.8** includes noncommercial production from these areas; however, reserves have not been booked pending commercial production.

5.1.4.5 Commingling of CBM with Conventional Natural Gas

The first production of CBM in Alberta was attempted in the 1970s, but the first CBM pool was not defined by the AER until 1995. Significant development with commercial production commenced in 2002. The actual CBM production to date continues to be uncertain because of the difficulty differentiating CBM from conventional gas production where commingled production occurs.

Gas commingling is the unsegregated production of gas from more than one pool in a wellbore. For CBM, this includes the commingling of two or more CBM zones, as well as the commingling of one or more CBM zones with one or more conventional gas pools.

As the Horseshoe Canyon and Belly River formations generally contain "dry CBM" with little or no pumping of water required, the commingling of CBM and other conventional gas pools is common. Because many of the sandstone gas reservoirs in these strata may be marginally economic or uneconomic if produced separately, commingling with CBM can be beneficial from a resource conservation perspective. In some circumstances, commingling can have the additional benefit of minimizing surface impact by reducing the number of wells needed to extract the same resource.

CBM hybrid wells lack segregated reservoir data from commingled zones, making reserve estimation more difficult. Many hybrid wells report only CBM production, even though analysis of the wells indicates that there is unsegregated production of both CBM and conventional gas. Recompleted wells with new CBM production may not report to a separate production occurrence. To address these data constraints, the following was done for wells with commingled production:

- Wells with completions that were determined to be only in coal were assigned as CBM-only production.
- The CBM production contribution from hybrid wells was interpolated from more than 1300 CBM control wells and numerous other wells with confirmed CBM-only production. The volume of CBM production was then subtracted from the total volume to give the conventional gas production.
- CBM production from conventional wells recompleted for CBM and not reported separately was included. An administrative process is in place to correct for the CBM production in these cases.

5.1.5 Shale Gas Resources

Shales are the traditional source rocks for conventional hydrocarbon accumulations, as well as a seal for conventional reservoirs. More recently, organic-rich shales have become a target for the production of gas, natural gas liquids, and oil.

Typically, these fine-grained rocks have an extremely low matrix permeability, and stimulation is required to produce fluids from the rock. Shale gas or shale oil is not restricted to shale since claystones, mudstones, siltstones, fine-grained sandstones, and carbonates can also be found within potential shale gas strata. The AER's recent study on shale- and siltstone-hosted hydrocarbon resources is discussed in **Section 2.2.2**.

More than 15 shale formations exhibit a potential for shale gas, natural gas liquids, or oil. The generalized stratigraphic chart of formations shown in **Figure R5.10** details the formations (indicated with red shading) that have organic matter that could potentially produce gas or oil. Not all of these formations are source rocks (i.e., are organic rich); some contain small amounts of organic matter and may be more like low-permeability strata or aquitards than organic-rich shale.

Exploration for shale gas, natural gas liquids, and oil is taking place in many of the formations highlighted in **Figure R5.10**. Receiving most of the attention are the Duvernay (Woodbend Group), Banff/Exshaw, and Nordegg (Fernie Group) formations as these strata are rich in natural gas liquids and oil. The depth from the surface to the shale formations increases westwards in Alberta. Typically, the deeper formations have a higher formation pressure, which is favourable for shale gas exploration.

The geographic distribution of significant shale gas horizons in the upper half of the WCSB is shown in **Figure R5.11**. The lower half of the WCSB is shown in **Figure R5.12**.

5.1.6 Ultimate Potential of Conventional Natural Gas

The Alberta Energy and Utilities Board (EUB; a predecessor of the AER) and the National Energy Board (NEB) jointly released *EUB/NEB Report 2005-A: Alberta's Ultimate Potential for Conventional Natural Gas*, an updated estimate of the ultimate potential for conventional natural gas. The EUB adopted the medium case of the report, representing a volume of 6276 109 m^3 (223 Tcf) "as is" or 6528 10^9 m^3 (232 Tcf) at the equivalent standard heating value of 37.4 MJ/m^3, as Alberta's ultimate potential. This estimate does not include unconventional gas, such as CBM.

Figure R5.13 shows the historical and forecast growth in initial established reserves of marketable gas. Historical growth up to 2013 equalled 5683 10^9 m^3. **Figure R5.14** plots production and remaining established reserves of marketable gas compared with the estimate of ultimate potential.

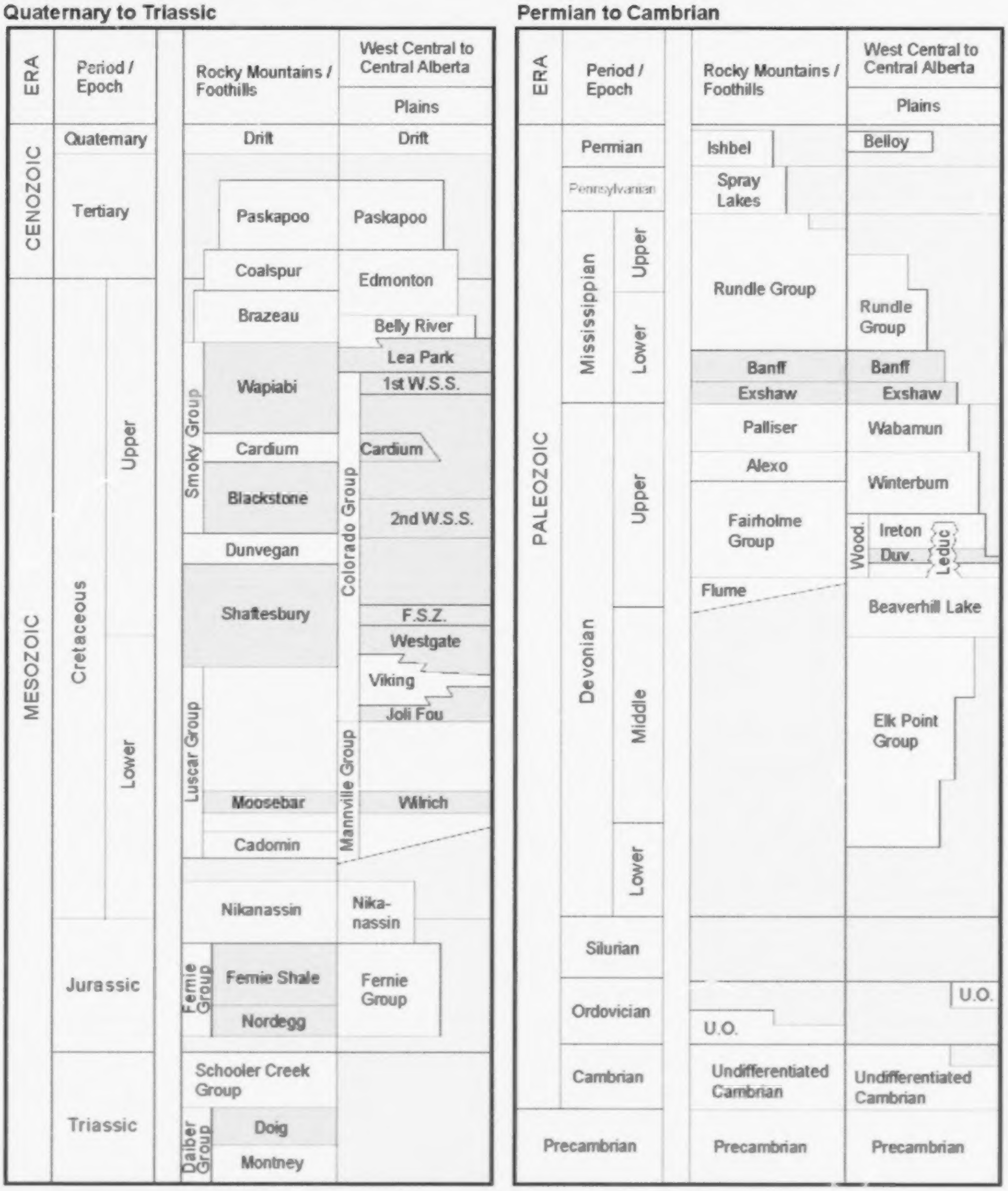
Table R5.9 provides details about the ultimate potential of marketable gas, with all values shown both "as is" and converted to the equivalent standard heating value of 37.4 MJ/m^3. It shows that initial established marketable reserves of 5421 10^9 m^3, or 86 per cent of the ultimate potential of 6276 10^9 m^3 ("as is" volumes), have been discovered as of year-end 2013. This leaves 855 10^9 m^3, or 14 per cent, as yet-to-be-discovered reserves. Cumulative production of 4523 10^9 m^3 at year-end 2013 represents 72 per cent of the ultimate potential, leaving 1753 10^9 m^3, or 28 per cent, available for future use.

The regional distribution of initial established reserves, remaining established reserves, and yet-to-be-established reserves is shown by PSAC area in **Figure R5.15**. It shows that the PSAC Area 2 contains 40 per cent of the remaining established reserves, and PSAC Area 7 contains 28 per cent of the yet-to-be-established reserves. Although most gas wells have been drilled in the southern plains (PSAC Areas 3, 4, and 5), **Figure R5.15** shows that, based on *EUB/NEB Report 2005-A*, Alberta conventional natural gas supplies will continue to depend on significant new discoveries in all PSAC areas.

Figure R5.16 shows by geological period the discovered and ultimate potential gas in-place for year-end 2005. It illustrates that 57 per cent of the ultimate potential gas in-place is in the Upper and Lower Cretaceous. Discovered gas in-place represents the known value as of December 2013. Current methods of evaluating gas in-place have changed from discrete pooling of wells in 2005 to more of a block-type model in areas such as the development entities and southeastern Alberta. This has resulted in the current discovered gas in-place being greater than the 2005 forecasted ultimate gas in-place for the Upper Cretaceous.

Figure R5.10

Potential shale gas strata



Abbreviations:
1st W.S.S. – First White Speckled Shale
2nd W.S.S. – Second White Speckled Shale
Duv. – Duvernay
F.S.Z. – Fish Scales Zone
U.O. – Undifferentiated Ordovician
Wood. – Woodbend Group

Potential shale gas strata
Absent

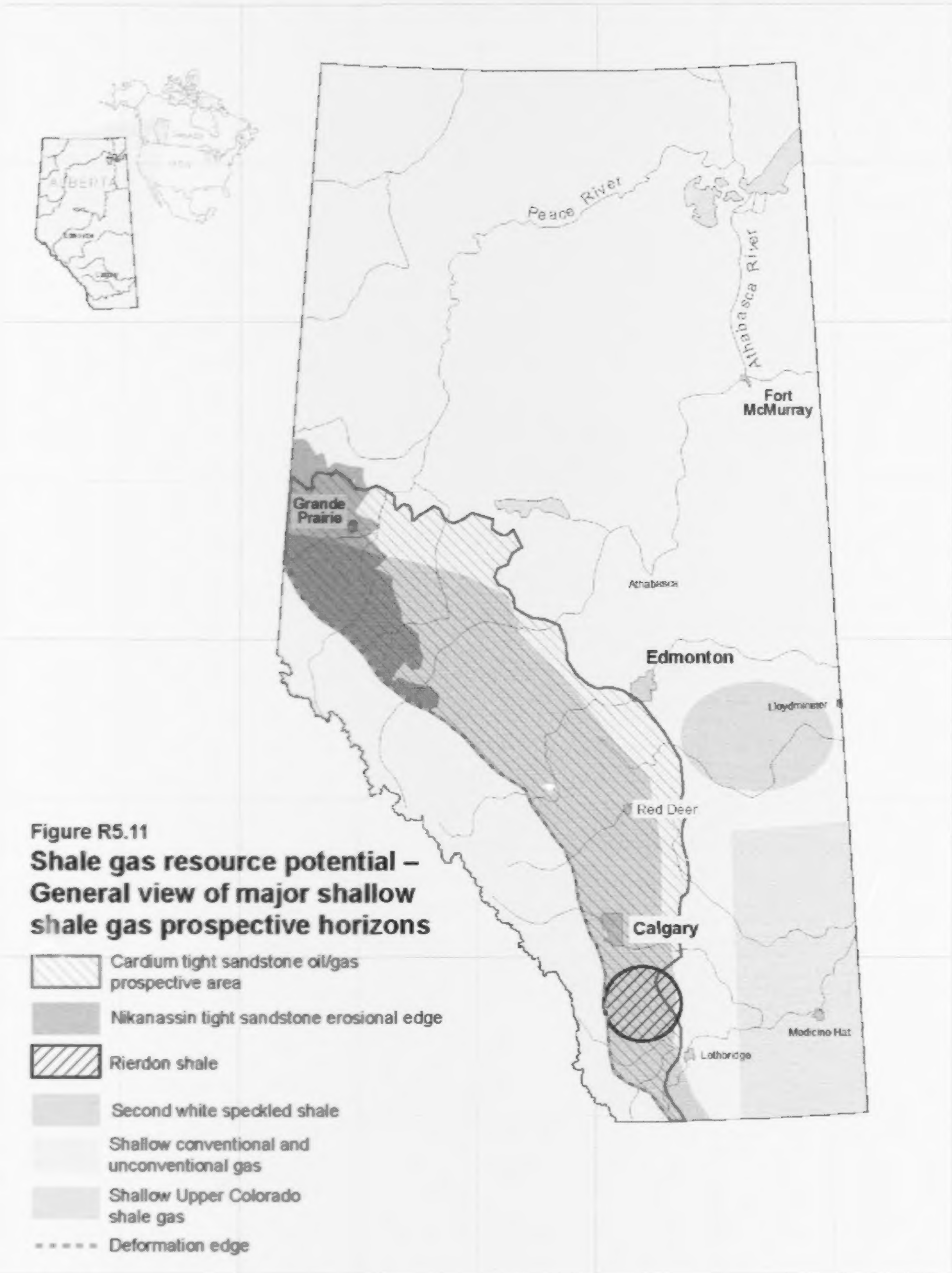


Figure R5.11
Shale gas resource potential – General view of major shallow shale gas prospective horizons

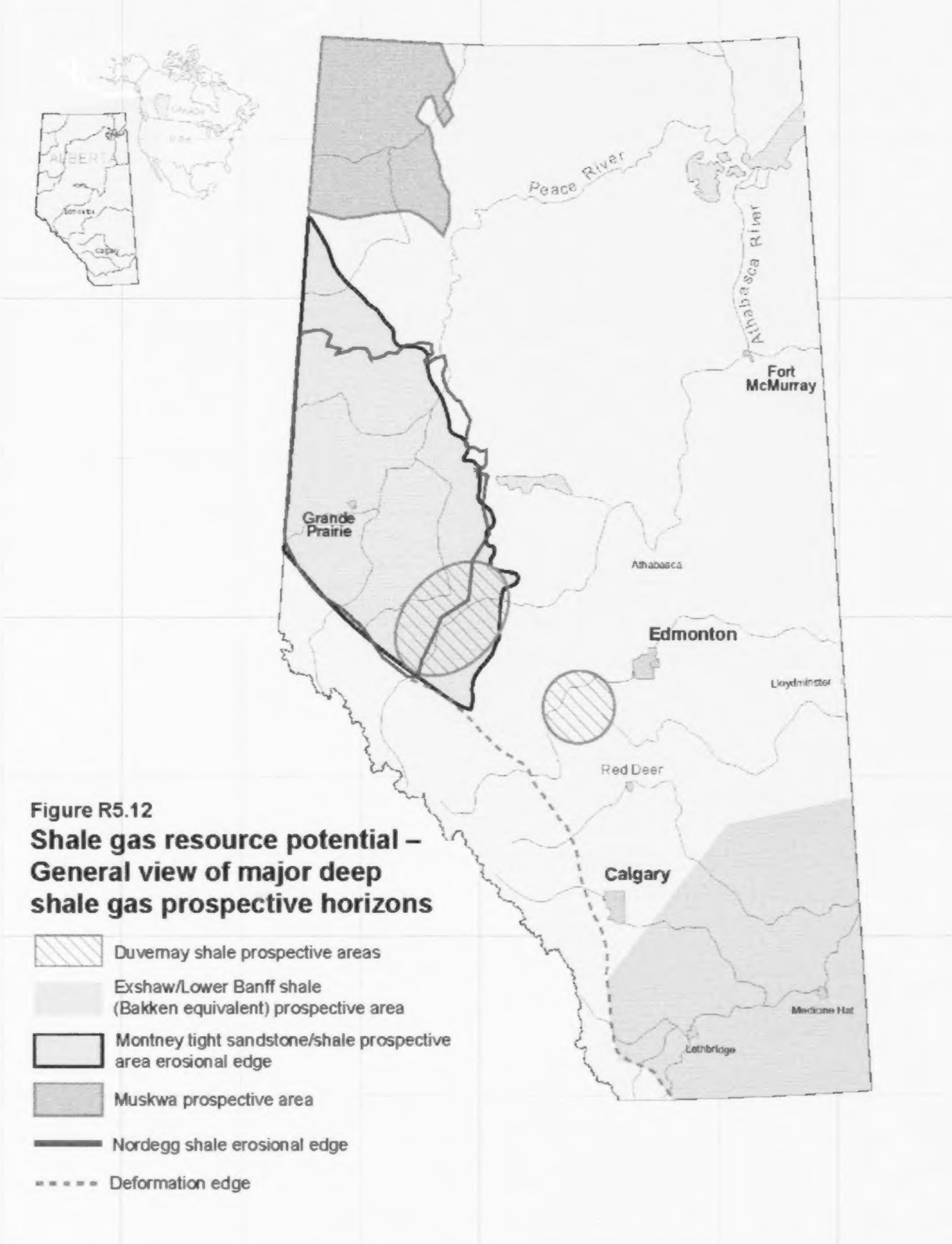


Figure R5.12

Shale gas resource potential – General view of major deep shale gas prospective horizons

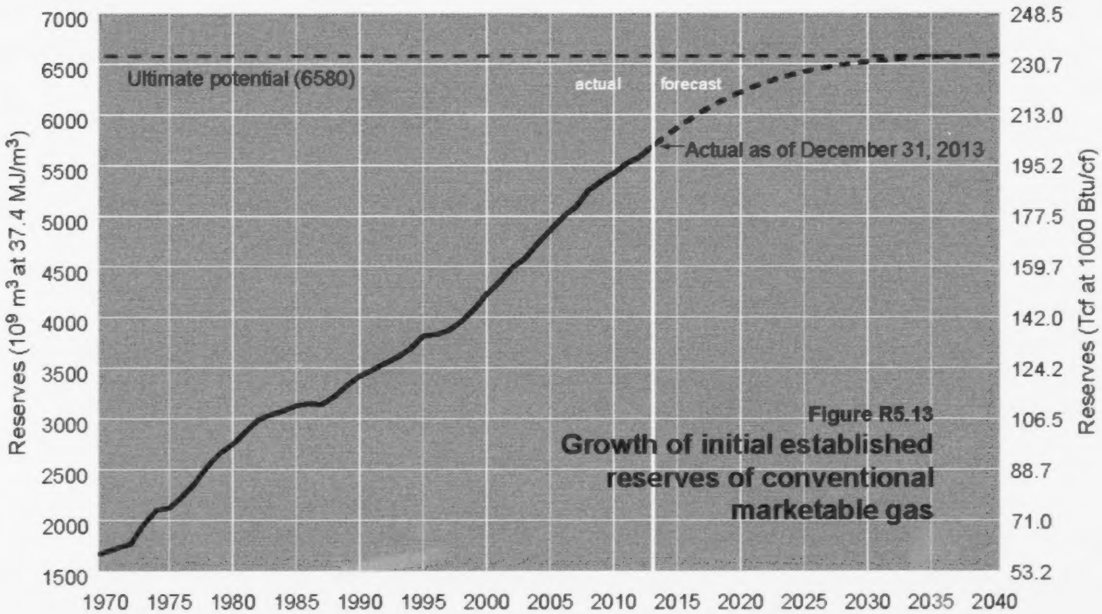


Figure R5.13
Growth of initial established reserves of conventional marketable gas

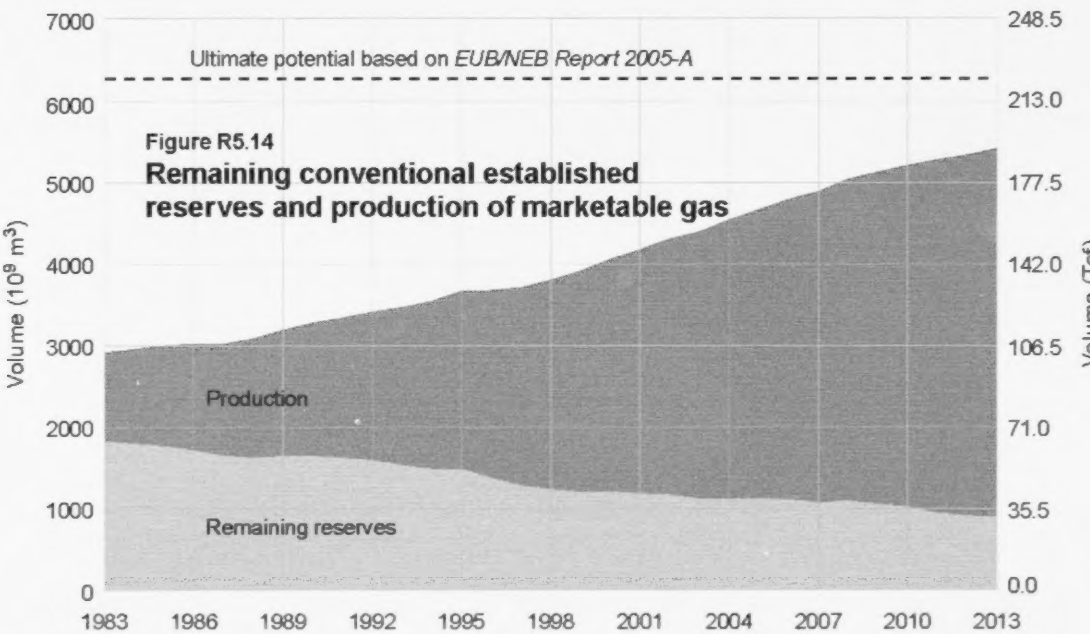


Figure R5.14
Remaining conventional established reserves and production of marketable gas

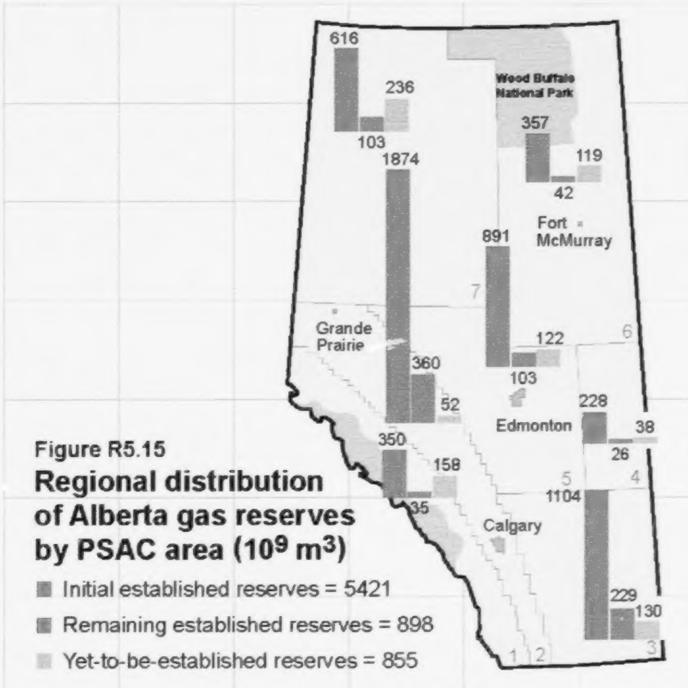


Figure R5.15
Regional distribution of Alberta gas reserves by PSAC area (10^9 m^3)

- Initial established reserves = 5421
- Remaining established reserves = 898
- Yet-to-be-established reserves = 855

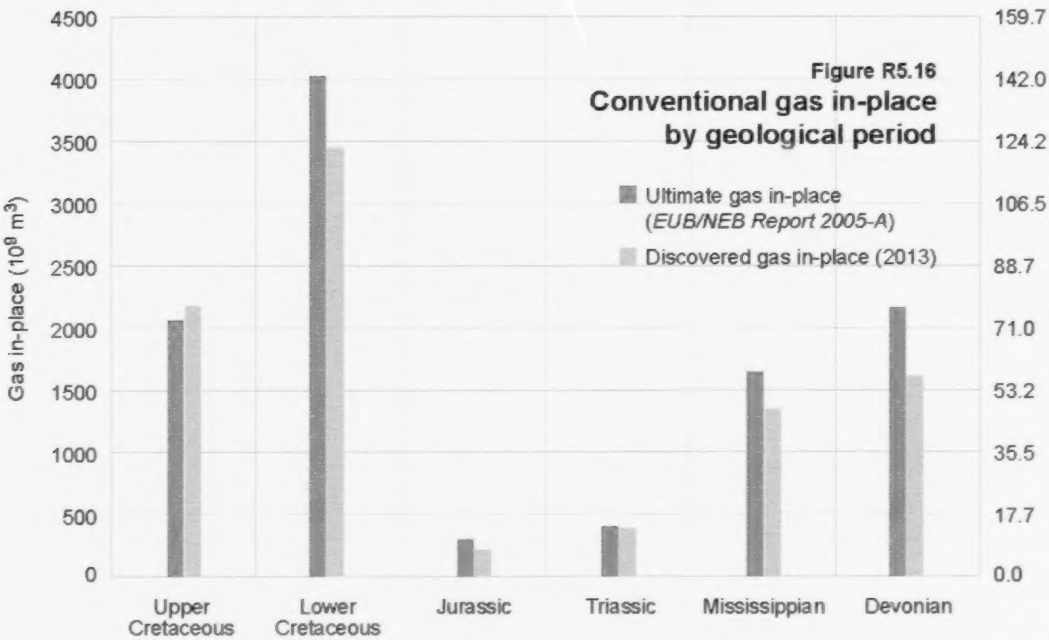


Figure R5.16
Conventional gas in-place by geological period

5.1.7 Ultimate CBM Gas In-Place

The Alberta Geological Survey (AGS), in *Earth Sciences Report 2003-03*, estimated that there are 14 trillion (10^{12}) m^3 (500 Tcf) of gas in-place within all of the coal in Alberta. This estimate is accepted as the initial determination of Alberta's ultimate CBM gas in-place (see **Table R5.10**). However, due to the early stage of CBM development and the resulting uncertainty of recovery factors, the recoverable portion—the ultimate potential—has yet to be determined.

Although not a type of natural gas, there is potential in Alberta for the production of synthetic gas from coal and other sources. Synthetic gas from coal is discussed in **Section 8**.

5.1.8 Ultimate Potential of Shale Gas

While the AER has yet to do a full provincial analysis of natural gas in shale-hosted reservoirs, the recent report *Energy Briefing Note – The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta* (discussed in **Section 2.3.3**) has given an estimate for the Montney Formation, one of the largest shale formations likely to produce some volumes of natural gas in the future. The report stated an ultimate potential of 5042 10^9 m^3 of natural gas in the Alberta portion of the Montney Formation.

Table R5.9 Remaining ultimate potential of marketable conventional gas, 2013 (10^9 m^3)

	Gross heating value	
	As is (39.2 MJ/m^3)	At 37.4 MJ/m^3
Ultimate potential	6 276	6 580
Minus initial established reserves	-5 421	-5 683
Yet-to-be-established reserves	**855**	**897**
Initial established reserves	5 421	5 683
Minus cumulative production	-4 523	-4 742
Remaining established reserves	**898**	**941**
Yet-to-be-established reserves	855	897
Plus remaining established reserves	+898	+941
Remaining ultimate potential	**1 753**	**1 838**

Table R5.10 Ultimate CBM gas in-place

Area	10^{12} m^3	Tcf[a]
Upper Cretaceous/Tertiary – Plains	4.16	148
Mannville coals – Plains	9.06	321
Foothills/Mountains	0.88	31
Total	**14.10**	**500**

Source: *EUB/AGS Earth Sciences Report 2003-03*.

[a] Tcf = trillion cubic feet.

5.2 Supply of and Demand for Natural Gas

In projecting marketable natural gas production, the AER considers three components: expected production from existing producing wells, expected production from new wells placed on production, and gas production from oil wells. The AER also takes into account its estimates of the remaining established and yet-to-be established reserves of natural gas in the province. The AER projects conventional gas production from oil wells and gas wells separately from CBM wells. The forecasts are combined and referred to as total gas production in Alberta. The production of natural gas from shale horizons remains limited and, consequently, no forecast is given in this report; however, this may change within the forecast period of ten years.

The AER annually reviews the projected demand for Alberta natural gas. The focus of these reviews is on natural gas use within Alberta. To do this, the AER undertakes a detailed analysis of a number of factors that influence gas consumption in the province, such as population growth, industrial activity, alternative energy sources, and other factors.

5.2.1 Marketable Natural Gas Production – 2013

With weak drilling activity for natural gas for the seventh year in a row, Alberta's production continued to slide. Since 2007, marketable natural gas production in Alberta has declined by 28 per cent. In 2013, total marketable natural gas production in Alberta, including unconventional production, declined by 2.6 per cent from 287.7 10^6 m^3/d to an average of 280.2 10^6 m^3/d. In 2013, natural gas from conventional gas and oil wells placed on production, at 258.7 10^6 m^3/d (standardized to 37.4 MJ/m^3), represented 92.3 per cent of production. The remaining 7.7 per cent of gas supply came from CBM and shale gas wells placed on production at an average 20.9 10^6 m^3/d and 0.6 10^6 m^3/d, respectively.

Total production from identified CBM and CBM hybrid wells placed on production decreased 6.1 per cent in 2013 to 20.9 10^6 m^3/d. Gas production from gas wells completed in the Horseshoe Canyon play area was 19.17 10^6 m^3/d, representing 91.6 per cent of total CBM production. Gas production from the Mannville Group averaged 1.8 10^6 m^3/d. Total production volume includes production from gas wells outside the defined CBM subareas.

The percentage of sour natural gas relative to the total gas production decreased from 31 per cent in 2000 to 19 per cent in 2013 because of a decline in production from the large sour gas pools in the province.

Marketable natural gas production volumes for conventional gas are calculated based on production data from the supply and disposition of marketable gas section of *ST3: Alberta Energy Resource Industries Monthly Statistics*, as shown in **Table S5.1**. Gas production from CBM and shale gas wells placed on production is determined separately.

Major factors affecting Alberta natural gas production are basin maturity, drilling and well activity, the location of Alberta's reserves, well production characteristics, gas liquids content, market demand, and natural gas prices and their volatility.

Table S5.1 Conventional marketable natural gas volumes (10^9 m^3)

Conventional marketable gas production	2013
Total raw gas production including storage withdrawals	119.9
Minus production from CBM and hybrid wells placed on production	-7.6
Minus production from shale gas wells placed on production	-0.2
Total conventional raw gas production	112.1
Minus storage withdrawals	-6.1
Net raw gas production	106.0
Minus total injection	-2.2
Net raw gas production	103.8
Minus processing shrinkage—raw	-6.9
Minus flared—raw	-0.8
Minus vented—raw	-0.5
Minus fuel—raw	-9.4
Plus storage injections	4.7
Conventional marketable gas production at "as is" conditions	90.8
Conventional marketable gas production at 37.4 MJ/m^3	94.4
Average daily rate of conventional marketable gas at 37.4 MJ/m^3	(258.7 10^6 m^3/d)

In the last few years, Alberta's natural gas industry has been shaped by natural gas prices, horizontal wells, completion techniques, and capital investment. In 2013, the Alberta Energy Company storage hub (AECO-C)[3] daily price averaged \$3.34 per gigajoule (GJ), up a significant 32.0 per cent from the 2012 daily average of \$2.53/GJ; however, this is still low compared to the daily averages of \$4.35/GJ in 2010 and \$8.57/GJ in 2008. With natural gas prices averaging below the \$4.00/GJ level, investment in conventional gas development has declined as prices do not support Alberta's relatively high drilling and development costs. This has resulted in a year-over-year reduction in both gas drilling activity and production.

Natural gas producers in Alberta and elsewhere are preferentially developing gas plays containing natural gas liquids (wet gas) as a way to offset the low natural gas prices. Propane, butanes, and pentanes plus are by-products of natural gas and are priced relative to crude oil. In 2013, the average price of Alberta light-medium was \$552.35/m^3, whereas the price of pentanes plus was \$652.96/m^3 and the price of butane was \$487.60/m^3. Natural gas producers with a steady stream of natural gas liquids output can, therefore, continue to drill new wells economically.

Another factor shaping Alberta's natural gas industry in 2013 was the continuing increase in well productivity. To combat the low price of natural gas, producers in Alberta are seeking higher initial productivity rates by drilling more horizontal gas wells and using multistage fracturing technology, which substantially improves well productivity. Producers are also targeting wet gas reservoirs with this technology with the result that some of

[3] The AECO-C hub is a trading point that represents the main pricing index for Albertan and Canadian natural gas.

these zones are proving to have higher than expected liquids content and consequently are known as liquids rich. In 2013, horizontal wells placed on production in Alberta increased by 61 per cent, whereas vertical wells placed on production decreased by 21 per cent.

The third factor affecting natural gas activity in Alberta is the competition for investment dollars among commodities. In the current price environment, investment has been moving away from dry gas targets and flowing to crude oil, bitumen, and wet natural gas development. The resurgence in crude oil drilling activity is a result of high crude oil prices and the successful application of multistage fracturing technology in horizontal wells. To illustrate this point, the Alberta price ratio[4] of gas to light-medium oil on an energy content basis averaged 0.20 in 2013, compared to an average of 0.66 from 2000 to 2008.

5.2.2 Conventional Natural Gas – 2013

Gas wells placed on production include newly drilled wells placed on production and recompletions into new zones of existing wells. This section identifies recompletions as those wells placed on production at least one year after the finished drilling date. In previous reports, the AER used the term "connections" to represent all wells placed on production. Starting with this report, the term "wells placed on production" will be used to maintain consistency with other sections of the report.

5.2.2.1 Conventional Natural Gas Wells Placed on Production

Figure S5.1 shows the number of conventional gas wells placed on production in Alberta in the last two years by PSAC area. In 2013, 1019 new conventional gas wells were placed on production in the province, which is the seventh straight year of reductions in new conventional gas wells. The number of gas wells placed on production dropped by 14.3 per cent in 2013 and has not been this low since 1987. The continued lower natural gas price in 2013, as well as natural gas producers' focus on high-capital horizontal wells with the application of multistage fracturing technology, is reflected in this decrease.

Conventional gas well activity for 2013 and 2012 is shown in **Table S5.2**. The table provides information on the number of vertical or directional wells versus horizontal wells drilled in the province. The table also breaks down the number of new gas wells placed on production versus wells recompleted in existing wellbores and placed on production. In 2013, about 19 per cent of gas wells were recompletions into existing wellbores.

Since 2011, the number of vertical wells placed on production in the province has fallen by a significant 77 per cent, whereas the number of horizontal wells placed on production increased by 9 per cent. In 2013, 62 per cent of new gas wells placed on production were horizontal wells, compared with 53 per cent in 2012 and only 3 per cent in 2008.

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4 If consumers were to pay the same price for a unit of gas as they would for a smaller unit of light-medium crude oil containing the same energy content as the unit of gas, the gas to light-medium price ratio would be 1.00 (parity being achieved). However, for various reasons, oil is intrinsically valued higher than gas and the price ratio is often less than 0.50.

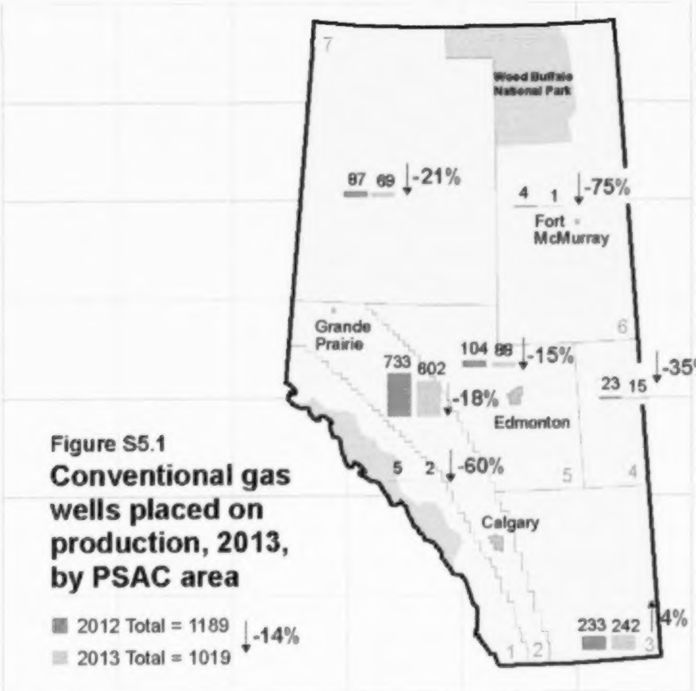


Figure S5.1
Conventional gas wells placed on production, 2013, by PSAC area

Table S5.2 Conventional gas wells placed on production by well type

	New wells placed on production			Recompletions			Total		
Well type	**2013**	**2012**	**2011**	**2013**	**2012**	**2011**	**2013**	**2012**	**2011**
Vertical/directional wells	240	366	1 229	150	188	504	390	554	1 733
Horizontal wells	587	622	564	42	13	13	629	635	577
Total	827	988	1 793	192	201	517	1 019	1 189	2 310

The number of natural gas horizontal multistage fractured wells is also increasing as a percentage of the total horizontal wells in the province. In 2012, the year of the most recent data, about 79 per cent of horizontal wells were completed with multistage fracturing, a significant increase when compared to 32 per cent in 2008. Overall, the number of wells placed on production in 2013 has decreased by 56 per cent since 2011.

Despite low well production rates, about 50 per cent of conventional gas activity has traditionally been focused on the shallow gas plays in southeastern Alberta because of the lower cost of drilling, existing infrastructure, and short tie-in times. However, with lower natural gas prices, the trend is changing significantly. The share of new wells in southeastern Alberta (an area containing mostly dry gas represented by PSAC Area 3) dropped from 40 per cent in 2011 to 24 per cent in 2013, far below 2004 when the share of new wells peaked at 56 per cent. However, in 2013, vertical wells placed on production in PSAC Area 3 increased by 24 per cent, whereas horizontal wells placed on production decreased by 38 per cent since producers are taking advantage of slightly higher gas prices by drilling lower cost shallow gas wells that can quickly be put on production.

Meanwhile, the share in PSAC Area 2 (an area of more wet gas) increased from 39 per cent in 2011 to 59 per cent 2013, significantly higher than 12 per cent in 2004. The number of horizontal wells placed on production in PSAC Area 2 increased by 12 per cent in 2013, whereas the number of vertical natural gas wells placed on production decreased by 60 per cent.

5.2.2.2 Production Trends

Figure S5.2 illustrates historical conventional marketable gas average daily production, including gas from oil wells, by PSAC area. Production in all areas of the province decreased from 2012 to 2013. Only gas from oil well production increased in 2013. The top three producing areas in the province—PSAC Areas 2, 3, and 7—are responsible for 43.3 per cent, 13.5 per cent, and 10.6 per cent of gas production in 2013, respectively.

Figure S5.3 shows that from 1993 to 2009, while the total number of producing conventional gas wells increased, average daily gas production decreased after reaching its peak in 2001 as the numbers of new conventional gas wells each year was insufficient to offset production declines in existing gas wells. The first year in recent history in which the number of conventional gas wells dropped over the previous year was in 2010, and this trend has continued in 2013. In 2013, the number of producing conventional gas wells declined to 104 426 after reaching a high of 113 450 in 2009.

Historical conventional raw gas average daily production by year the well was placed on production is presented in **Figure S5.4**. Natural gas production from oil wells has remained relatively stable, as shown by the band on the bottom of the chart. It has increased in the last two years due to the increase in Alberta's crude oil production. The percentages on the right-hand side of the figure represent each year's share of total production in 2013. About 9 per cent of conventional gas production in 2013 came from wells placed on production in 2013. Wells placed on production before 2003 contributed 34 per cent.

Figure S5.5 compares total raw natural gas production in Alberta with both Texas and Louisiana onshore production and total U.S. gas production over the past 50 years. Both Texas and Louisiana show peak gas production in the late 1960s and early 1970s, while Alberta's production has a noticeably flatter production profile, peaking in 2001. For both Texas and Louisiana, gas production declined somewhat steeply after reaching peak production, but after a decade of decline, production rates stabilized. Only recently have they seen an increase again in gas production because of growth in shale gas production.

The long-term outlook for North American gas supply has changed with the recent growth in supply from shale gas production. With the success of the Barnett and Eagle Ford shales in Texas, and the expected potential of other shale gas plays in the United States—particularly the Marcellus, Haynesville, Woodford, and Fayetteville shales, as well as the Horn River and Montney shale plays in northeastern British Columbia (B.C.)—shale gas production continues to grow. The U.S. Energy Information Administration expects that shale gas production in the United States will increase from 9.35 Tcf (263.4 10^9 m^3) in 2013 (38.7 per cent of total U.S. dry gas production) to 19.56 Tcf (551.08 10^9 m^3) in 2038 (52.8 per cent of total U.S. dry gas production).

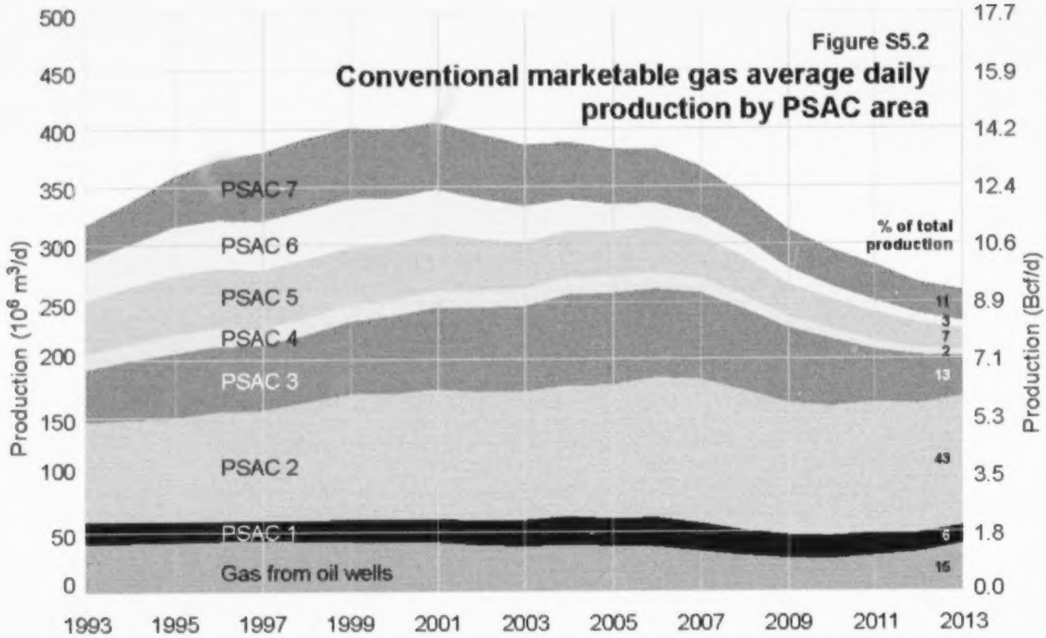


Figure S5.2
Conventional marketable gas average daily production by PSAC area
Production (10⁶ m³/d)
Production (Bcf/d)
% of total production
PSAC 7
PSAC 6
PSAC 5
PSAC 4
PSAC 3
PSAC 2
PSAC 1
Gas from oil wells
11
3
7
2
13
43
6
15
500
450
400
350
300
250
200
150
100
50
0
17.7
15.9
14.2
12.4
10.6
8.9
7.1
5.3
3.5
1.8
0.0
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013

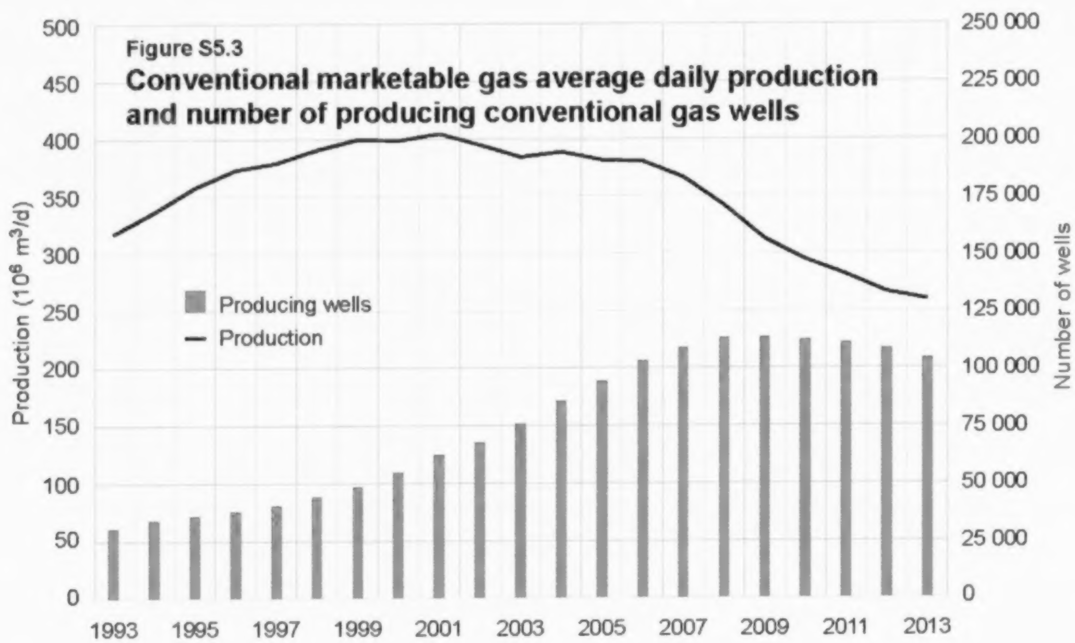


Figure S5.3
Conventional marketable gas average daily production and number of producing conventional gas wells
Producing wells
Production
Production (10⁶ m³/d)
Number of wells
500
450
400
350
300
250
200
150
100
50
0
250 000
225 000
200 000
175 000
150 000
125 000
100 000
75 000
50 000
25 000
0
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013

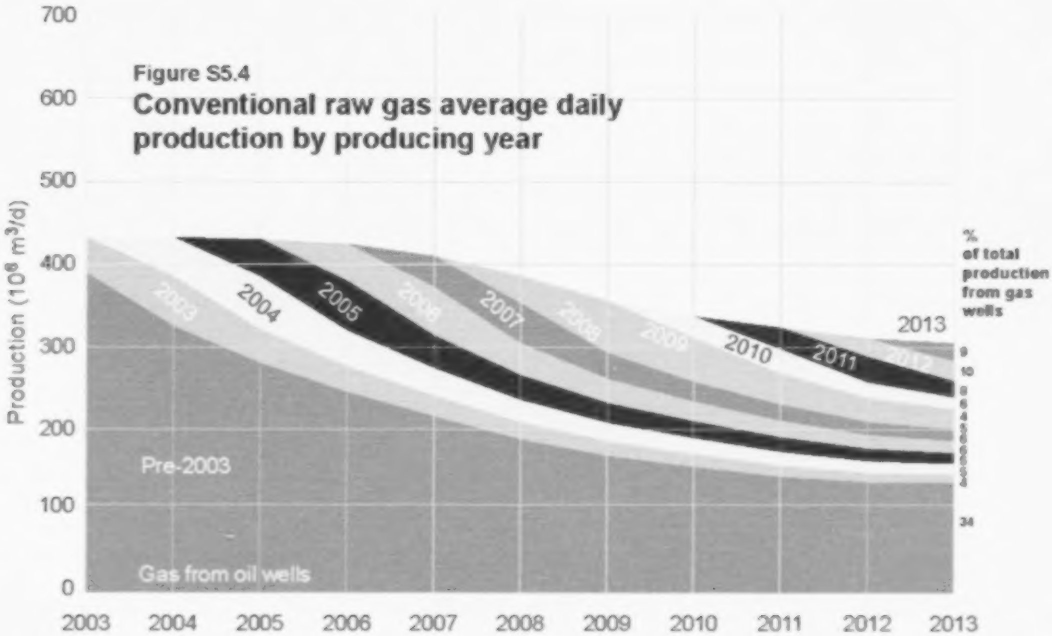


Figure S5.4
Conventional raw gas average daily production by producing year

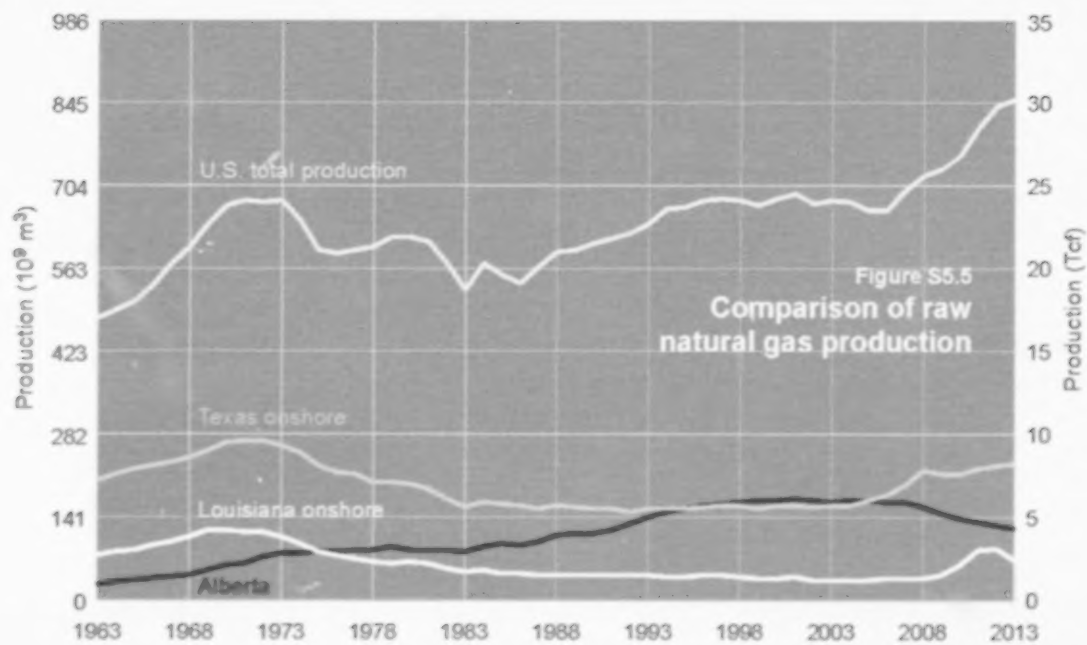


Figure S5.5
Comparison of raw natural gas production

5.2.2.3 Production Characteristics of Conventional Natural Gas Wells

Average initial productivity of newly producing conventional gas wells varies throughout the province and differs between vertical and horizontal well types. Average initial well productivity increased in all areas of the province with the exception of PSAC Area 1, where initial productivity rates declined. On average, horizontal well types have higher initial productivity rates than vertical wells, especially if completed with multistage fracturing. The average initial productivity rate for wells placed on production in 2012 for Alberta was 22.7 10^3 m^3/d, significantly higher than the 13.8 10^3 m^3/d for wells placed on production in 2011, and 9.9 10^3 m^3/d in 2010. The figure for 2013 is not available as the initial productivity rate is calculated using the first full calendar year following the on production date of a well. Well productivity has been adjusted for surface losses to reflect sales gas rates as opposed to raw gas rates.

Figure S5.6 shows average initial well productivity by well type for wells placed on production in 2012. PSAC Areas 2, 5, and 7 are where most horizontal wells have been brought on production. No horizontal gas wells were placed on production in PSAC Area 6 in 2012.

Figure S5.7 charts the number of producing gas wells by range of average daily productivity in 2013. About 66 per cent of producing gas wells (69 192) produced less than 1.0 10^3 m^3/d of raw gas. These gas wells produced at an average rate of 0.4 10^3 m^3/d and contributed less than 10 per cent of the total conventional natural gas production.

Less than 1 per cent of the conventional gas wells placed on production produced at rates over 50 10^3 m^3/d; however, they contributed about 25 per cent of total production, up from 21 per cent in 2012 as there are more high productive horizontal wells in this category.

5.2.3 Coalbed Methane

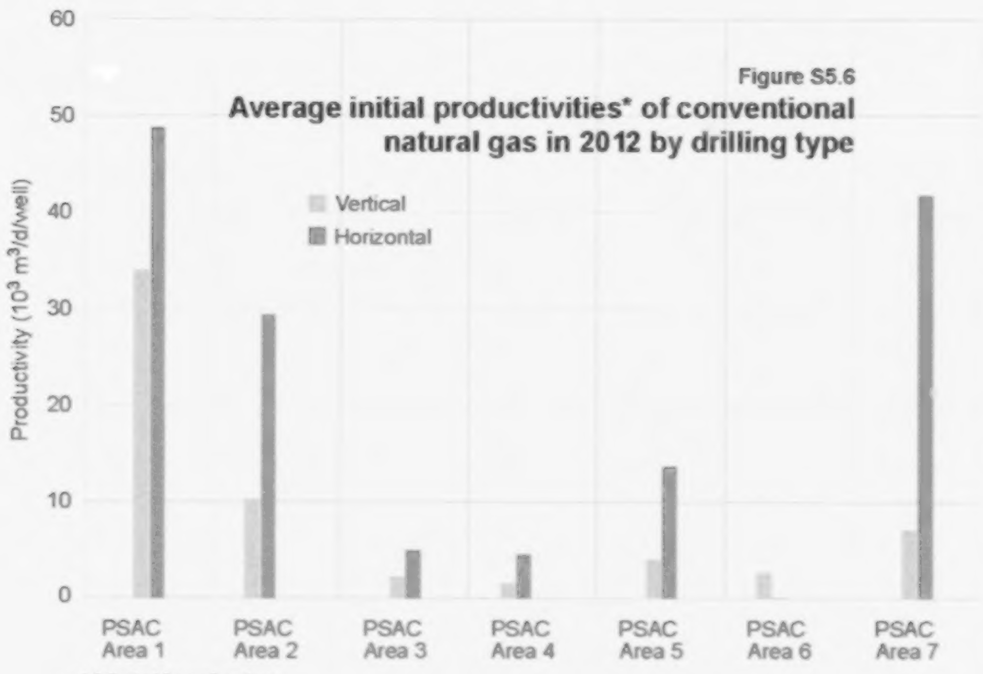
The AER identifies CBM and CBM hybrid wells using licensing data, production reporting, and detailed geological evaluations. All wells placed on production and volumes in this section are based on CBM well designations as of December 31, 2013.

5.2.3.1 Coalbed Methane Wells Placed on Production

In 2013, 130 new CBM and CBM hybrid wells were placed on production, all of them in the Horseshoe Canyon play area and all of them vertical wells. No new wells were placed on production in the Mannville Corbett play for the last two years due to higher capital and operating costs. Overall, new CBM and CBM hybrid wells placed on production decreased by 70 per cent in 2013 over 2012.

New CBM and CBM hybrid producing well activity for 2013 and 2012 is shown in **Table S5.3**. The table shows the number of new and recompleted CBM and CBM hybrid wells placed on production in vertical or directional wells and horizontal wells within the AER-defined CBM play areas.

Figure S5.6
Average initial productivities* of conventional natural gas in 2012 by drilling type



* Adjusted for surface loss.

Figure S5.7
Producing conventional gas wells and average productivity in 2013

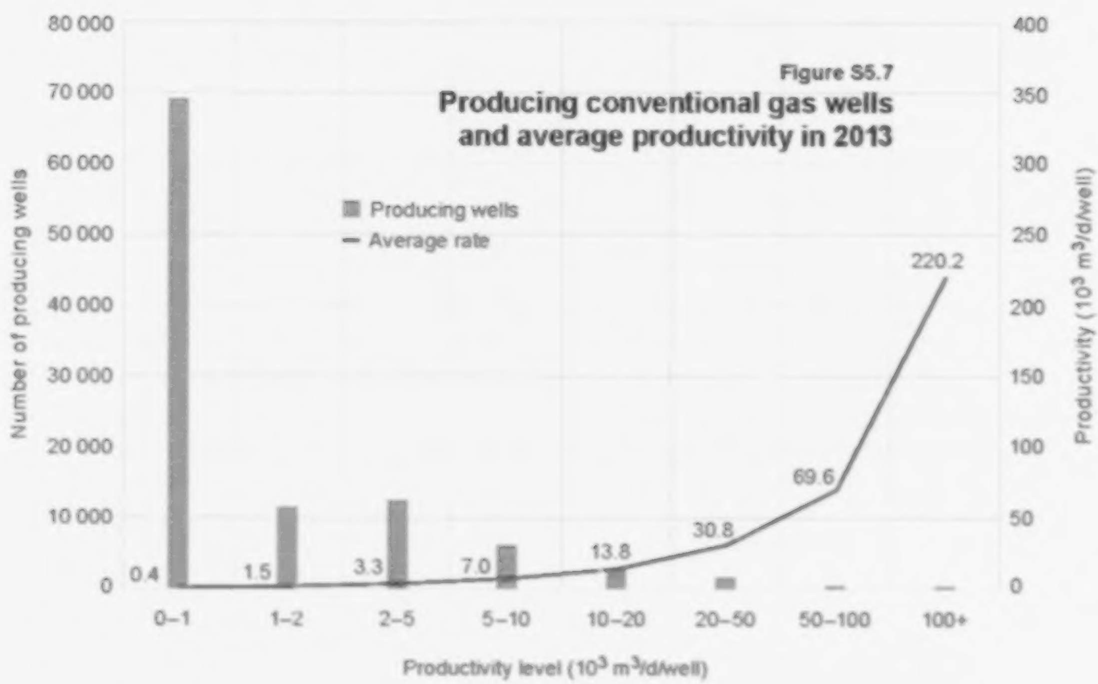


Table S5.3 CBM and CBM hybrid wells placed on production by well type and CBM play area

	New wells placed on production		Recompletions		Total	
CBM play subarea	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Vertical/directional wells						
Horseshoe Canyon	58	262	61	75	119	337
Mannville Corbett	0	0	0	0	0	0
Undefined[a]	0	75	11	21	11	96
Subtotal	58	337	72	96	130	433
Horizontal wells						
Horseshoe Canyon	0	0	0	0	0	0
Mannville Corbett	0	0	0	0	0	0
Undefined[a]	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0
Total	**58**	**337**	**72**	**96**	**130**	**433**

[a] Includes wells placed on production outside defined play subarea boundaries.

In 2013, about 55 per cent of the wells placed on production were recompletions into existing vertical wells, significantly higher than the 22 per cent recompleted in 2012. Producers are recompleting more wells due to the lower capital cost and faster production schedule versus drilling a new well and placing it on production.

5.2.3.2 Coalbed Methane Production Trends

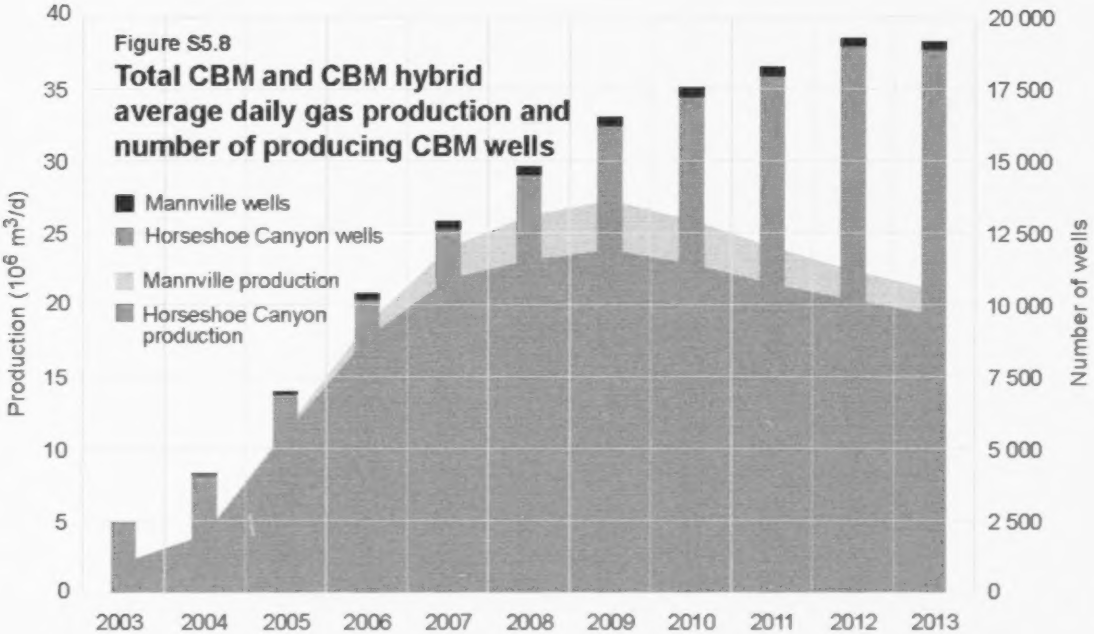
Total CBM and CBM hybrid average daily gas production and numbers of producing wells are shown in **Figure S5.8**. This figure shows that existing Mannville CBM wells account for 8.4 per cent of total CBM production but represent only 1.5 per cent of total producing CBM wells. Of the 290 producing wells in the Mannville area, 90 per cent are horizontal wells, while less than 1 per cent of the 18 842 producing wells in the Horseshoe Canyon are horizontal.

5.2.3.3 Production Characteristics of Coalbed Methane Wells

The average initial daily productivity rate in the Horseshoe Canyon area for wells drilled in 2012 was 1.2 10^3 m^3/d, unchanged from wells drilled in 2011. No wells were drilled in 2012 in the Mannville CBM area and only a few in 2011; consequently, no reliable average productivity rate could be calculated.

5.2.4 Shale Gas

The AER identifies shale gas wells placed on production using the designation submitted by the operator to PETRINEX (formerly known as the Petroleum Registry of Alberta). If required, these designations are evaluated and adjusted based on new information, resulting in revisions to historical annual numbers. All shale gas wells placed on production and volumes in this section are based on current well designations as of December 31, 2013.



5.2.4.1 Shale Gas Wells Placed on Production

The AER currently recognizes 108 producing shale and commingled shale gas wells in 2013. Horizontal gas wells drilled in low permeability gas-bearing formations in northwest Alberta are reported as conventional gas, and reserves associated with this development are included in the conventional gas category in this report; however, as the play extends into B.C., it becomes generally shalier and is defined as shale gas.

Shale gas average daily production in Alberta is shown in **Figure S5.9** along with the number of producing shale gas wells placed on production in each year. **Table S5.4** identifies the type of new shale wells placed on production in 2013 and 2012. About 95 per cent of the designated shale gas wells placed on production have been made in the last seven years, with most in 2008.

5.2.4.2 Shale Gas Production Trends

Seventy per cent of the 23 shale gas wells placed on production in the province in 2013 are located in PSAC Area 2 and accounted for 95 per cent of the shale gas production that came on production in 2013.

The average initial daily productivity rate for wells connected in 2012 was 6.7 10^3 m^3/d, higher than the 6.5 10^3 m^3/d for wells connected in 2011. The figure for 2013 is not available as initial productivity rate is calculated using the first full calendar year following the connection date of a well.

5.2.5 Supply Costs

Table S5.5 summarizes the estimated costs for conventional and CBM natural gas from selected areas in Alberta based on 2013 estimated costs and production profiles. The supply costs are based on representative wells in each

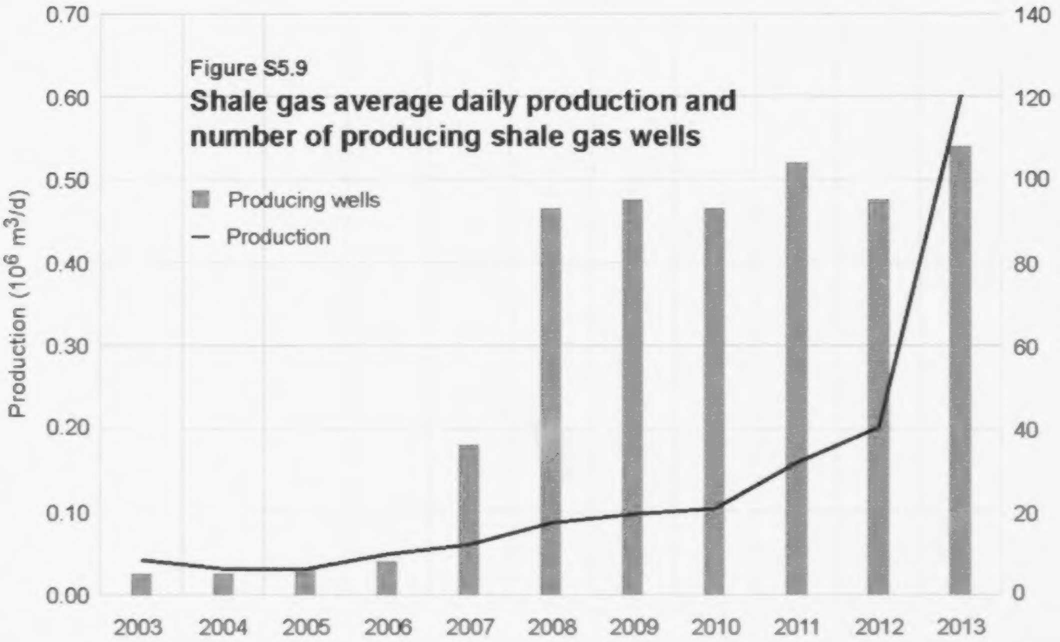


Figure S5.9
Shale gas average daily production and number of producing shale gas wells

Table S5.4 Shale gas wells placed on production by well type

	New wells placed on production		Recompletions		Total	
Well type	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Vertical wells	0	0	3	1	3	1
Horizontal wells	17	10	3	0	20	10
Total	17	10	6	1	23	11

PSAC area. Supply costs for different geological plays and PSAC areas vary significantly because of differing discovered reserves, production rates, well types, drilling and operating costs, royalties, and other factors. Therefore, the results may not be reflective of wells that differ from the representative well profiles used in the analysis.

The supply cost estimate for an average horizontal or vertical well in each PSAC area includes the following data: initial productivities, production decline rates, vertical drilled depths and total measured depths of the wells, gas composition, shrinkage, capital cost, operating costs, royalties and taxes, and a 10 per cent nominal rate of return. The supply costs in **Table S5.5** are not risked (i.e., assumes a 100 per cent success rate). The table shows that horizontal wells have lower supply costs compared with vertical wells; the higher initial productivities associated with horizontal wells offset their higher capital costs. Furthermore, wet gas (especially if it is liquids-rich) improves the economics of the development of gas wells and, therefore, wet gas wells have lower supply costs than dry gas production such as CBM. The representative wells in PSAC Areas 1, 2, 5, and 7 are assumed to have wet gas production.

Table S5.5 Natural gas supply costs for PSAC areas and CBM play areas[a]

Area	Type of well	Type of gas	Total measured depth (m)	Initial productivity (10^3 m^3/d)	Total capital cost ($000)	Fixed operating cost ($000/year)	Variable operating cost ($/$10^3$ m^3)	Natural gas supply cost ($/GJ)
PSAC 1	Directional	Sour	4500	51.7	18212	202	53.24	7.41
PSAC 2	Vertical	Sweet	2500	15.9	2722	54	35.5	3.75
PSAC 2	Horizontal	Sweet	4200	40	4664	61.2	56.8	2.48
PSAC 3	Vertical	Sweet	560	2.4	465	11.4	49.69	6.48
PSAC 4	Vertical	Sweet	900	2	985	30.98	30.17	14.69
PSAC 5	Vertical	Sweet	1150	5.2	1293	27.57	31.9	10.30
PSAC 5	Horizontal	Sweet	2600	23.2	2976	44.475	31.9	3.16
PSAC 6	Vertical	Sweet	500	3.5	689	34.63	35.5	10.62
PSAC 7	Vertical	Sweet	2300	12.9	2558	62.5	30.2	6.39
PSAC 7	Horizontal	Sweet	3500	45.7	8051	62.5	33.7	4.99
CBM-HSC[b]	Vertical	CBM	250	1.8	759	20.75	40.8	10.95
CBM-MAN[c]	Horizontal	CBM	2400	8.4	2171	27.58	31.9	9.67

[a] Data from petroCube and PSAC's *2014 Well Cost Study* have been used to estimate the supply costs in PSAC areas and CBM play areas.

[b] Horseshoe Canyon.

[c] Mannville Corbett.

The average AECO-C daily natural gas price in 2013 was $3.34/GJ, lower than the supply cost in many areas. Therefore, based on the assumptions used in the analysis, new gas developments were uneconomical in 2013 for most of the representative wells. However, some horizontal wet gas developments, mainly in PSAC Areas 2 and 5 were found to yield positive returns.

In addition to the higher initial productivity for horizontal wells, the new royalty framework released by the Government of Alberta, effective January 2011, and royalty holiday programs have also provided incentives for deep horizontal drilling.

The results in **Table S5.5** also indicate high supply costs for vertical wells in PSAC Areas 4, 5, and 6, as well as CBM wells producing from the Horseshoe Canyon and Mannville Corbett play areas. This is because of low initial well productivity, low natural gas liquids content, and/or relatively high capital costs per metre of drilling. The results are corroborated with the reduction of drilling activity in these areas.

5.2.6 Marketable Natural Gas Production – Forecast

In projecting conventional gas and CBM supply, the AER considers three components: expected production from existing conventional gas and CBM wells placed on production, expected production from new conventional gas and CBM wells placed on production in new and existing wells, and gas production from oil wells. The AER also takes into account its estimates of the remaining established and yet-to-be-established reserves of conventional natural gas in the province. Since shale gas development is in its early stages in Alberta, the AER does not have sufficient information to confidently forecast shale gas supply at this time.

To forecast gas production, production data from existing wells and from new wells drilled and placed on production each year have been analyzed. The number of new wells placed on production and the average productivity for the wells are the main determining factors used in projecting natural gas production volumes over the forecast period.

5.2.6.1 Conventional Gas

To project natural gas production from existing conventional gas wells placed on production, the AER assumes the following:

- Decline rates for gas production from existing conventional gas wells placed on production at year-end 2013 vary depending on such factors as the ages, types, and geological and geographical locations of the wells. Overall, however, it is assumed that rates will decline by 12 per cent per year over the forecast period based on observed performance. This is lower than last year's forecast of a 14 per cent annual decline. Decline rates are typically higher at the early stage of production and stabilize as gas production continues over time. The decline rate was lowered from last year's forecast as more gas has been produced from wells that have been producing for eight years or more. In 2013, about 54 per cent of total conventional gas production was from wells that were eight years or older, compared with 41 per cent in 2009.
- Production from existing conventional gas wells placed on production will average 222.3 10^6 m^3/d in 2014 and decline to 70.7 10^6 m^3/d in 2023.

Analyses on the initial productivities, decline rates, the numbers of producing wells, the remaining reserves, fixed and variable costs, the royalty regime, oil and natural gas prices, and returns on investment were conducted for each PSAC area. Separate analysis was conducted on horizontal and vertical wells for PSAC Areas 2, 5, and 7 because these areas have sufficient horizontal wells to support analysis. To project natural gas production from new conventional gas wells placed on production, the AER assumed the following:

- The number of conventional gas wells placed on production over the forecast period is projected to start at 1190 in 2014 and increase to 1939 by 2023. The number of forecast wells placed on production is higher relative to last year's forecast of 1425 in 2022 but significantly lower than 2012's forecast of 3800 in 2021. This is due to a higher natural gas price forecast relative to last year's forecast, a focus on less expensive shallow gas wells, and a shift from vertical and directional wells to horizontal wells. In addition, drilling activity in 2013 was lower than in 2012; however, year-end drilling data combined with natural gas licensing data and unusually high natural gas prices in the beginning of 2014 suggest drilling in 2014 will begin to recover.
- Conventional gas wells placed on production in PSAC Area 3 will represent 28 per cent of all new conventional gas wells placed on production in 2014, which will gradually decline to 22 per cent in 2023 as producers drill less capital intensive shallow dry gas wells. Over the forecast period, the AER expects that the shift in new wells from the dry gas of PSAC Area 3 to the wet gas of PSAC Areas 2, 5, and 7 will continue as gas producers see higher returns from gas with liquids. The average initial productivity of a new conventional gas well placed on production in PSAC Area 3 will be 2.0 10^3 m^3/d over the forecast period.

- The AER expects that PSAC Areas 2, 5, and 7 will represent 70 per cent of all conventional wells placed on production in 2014, increasing slightly to 73 per cent in 2023. Horizontal wells are projected to represent 75 per cent of the new wells placed on production in these PSAC areas in 2014, slightly declining to 65 per cent in 2023.
- Based on historical data, production from gas wells over the forecast period, although variable, will generally decline by 40 per cent in the first year, 27 per cent in the second year, 19 per cent in the third year, and 13 per cent in the fourth year. The decline rate will then continue to decrease gradually every year before reaching 10 per cent in the tenth year.
- Gas production from oil wells, based on observed performance, will average 38.9 10^3 m^3/d in 2014, and will gradually decrease to 31.8 10^3 m^3/d in 2023. This forecast reflects recent actual performance.
- The AER has forecast initial productivity for those wells expected to be placed on production within the forecast period by year and PSAC area. Within PSAC Areas 2, 5, and 7, a separate forecast was made for vertical and horizontal wells. Initial productivity for 2014 varied between 2.0 10^3 m^3/d in PSAC Area 4 to 51.7 10^3 m^3/d in PSAC Area 1. Relatively minor variation on the year-to-year initial productivity was also forecast.
- The AER also forecast decline rates for those wells expected to be placed on production within the forecast period by year and PSAC area. Within PSAC Areas 2, 5, and 7, a separate forecast was made for vertical and horizontal wells. Decline rates for 2014 varied between 28 per cent in PSAC Area 1 to 47 per cent in PSAC Area 5 for horizontal wells. Decline rates at the end of the forecast period in 2023 varied between 8 per cent in PSAC Area 1 to 13 per cent in PSAC Area 4.
- Finally, the AER also forecast the number of wells expected to be placed on production within the forecast period by year and PSAC area. Within PSAC Areas 2, 5, and 7, a separate forecast was made for vertical and horizontal wells. The number of wells forecast for 2014 varied between 1 in PSAC Area 6 to 463 in PSAC Area 2 for horizontal wells. The number of wells expected at the end of the forecast period in 2023 varied between 16 in PSAC Area 6 to 612 in PSAC Area 2 for horizontal wells. Across all PSAC areas, the AER expects 1190 wells to be placed on production in 2014 rising to 1939 in 2023.

Based on the remaining established and yet-to-be-established reserves, and the assumptions described above, the AER forecasts conventional marketable gas production to be 228.4 10^6 m^3/d in 2023. If conventional natural gas production rates follow the projection, Alberta will have recovered 82 per cent of the 6528 10^9 m^3 ultimate potential by 2023.

5.2.6.2 Coalbed Methane

In projecting CBM supply, the AER considers expected production from existing CBM wells placed on production and expected production from new CBM wells placed on production. These new CBM wells placed on production include CBM wells placed on production from new wells drilled and from recompletions into

existing non-CBM wells. Continual reclassification of CBM wells placed on production results in revisions to historical data and, therefore, changes to annual forecasts.

To forecast production from new CBM and CBM hybrid wells placed on production, the AER assumed the following:

- Over the forecast period, the majority of new CBM and CBM hybrid production will be from the Horseshoe Canyon play area.
- The number of CBM and CBM hybrid wells placed on production will be 130 in 2014 and will increase to 405 in 2023. This forecast is relatively unchanged from last year's projection due to the continuing low levels of activity reported in 2013 and the expectation that return on investment will not significantly improve over the forecast period because of lower gas prices.
- The average initial productivity of a new CBM well in the Horseshoe Canyon play area will be 1.3 10^3 m^3/d and gradually decrease to 0.8 10^3 m^3/d in 2023.

Production from CBM wells placed on production, which includes commingled production from conventional gas formations, is expected to be 14.1 10^6 m^3/d in 2023, relatively unchanged from last year's forecast. In 2013, CBM production contributed 7.2 per cent of the total Alberta marketable gas production, similar to that of the previous year, and is projected to contribute 6.0 per cent of the total Alberta marketable gas production in 2023, also similar to last year's forecast.

5.2.6.3 Shale Gas

As mentioned earlier, the AER does not have sufficient information to confidently forecast shale gas supply at this time. The extent of the economic viability of shale development in Alberta is currently unclear; however, it has the potential to become a significant source of supply. Commercial shale gas production is in its infancy, and it will take time to establish the long-term producibility of the resource. The pace of shale gas development will be affected by the natural gas price environment, supply costs, and technology.

5.2.6.4 Total Gas Production

The AER's forecast of conventional gas average daily production from gas wells in each PSAC area, conventional oil wells, and CBM production, are shown in **Figure S5.10**. The AER forecasts that total marketable gas production will decline from 271.4 10^6 m^3/d in 2014 to 242.5 10^6 m^3/d in 2023.

Figure S5.11 illustrates historical new wells placed on production for conventional, CBM, and shale gas wells, with a forecast for conventional and CBM wells, along with plant gate gas prices (see **Section 1** for a discussion on price forecasts).

Figure S5.12 shows average daily process gas production (rich in liquids) from bitumen upgrading and raw natural gas from bitumen wells. Gas from these sources is used primarily as fuel in oil sands development.

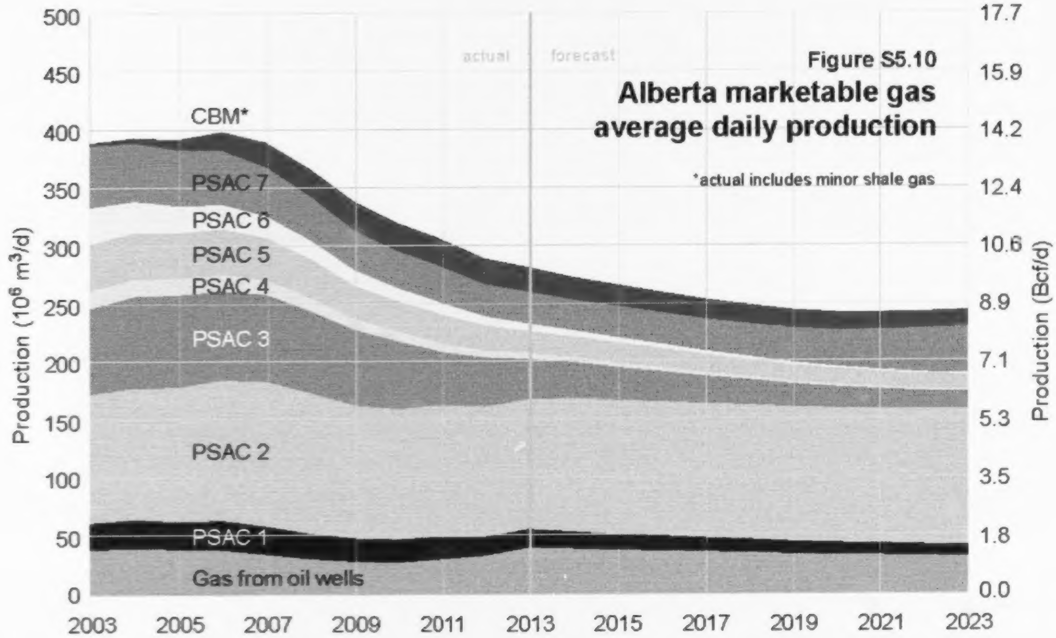


Figure S5.10
Alberta marketable gas average daily production
*actual includes minor shale gas
actual
forecast
CBM*
PSAC 7
PSAC 6
PSAC 5
PSAC 4
PSAC 3
PSAC 2
PSAC 1
Gas from oil wells
Production (10^6 m³/d)
Production (Bcf/d)
500
450
400
350
300
250
200
150
100
50
0
17.7
15.9
14.2
12.4
10.6
8.9
7.1
5.3
3.5
1.8
0.0
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023

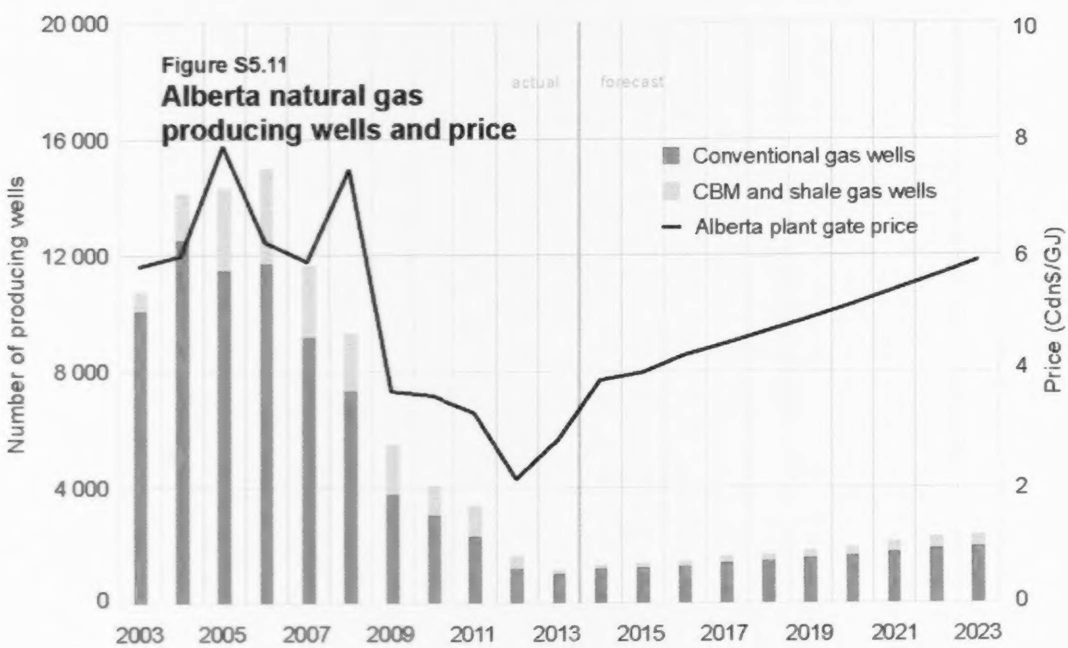


Figure S5.11
Alberta natural gas producing wells and price
actual
forecast
Conventional gas wells
CBM and shale gas wells
Alberta plant gate price
Number of producing wells
Price (Cdn$/GJ)
20 000
16 000
12 000
8 000
4 000
0
10
8
6
4
2
0
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023

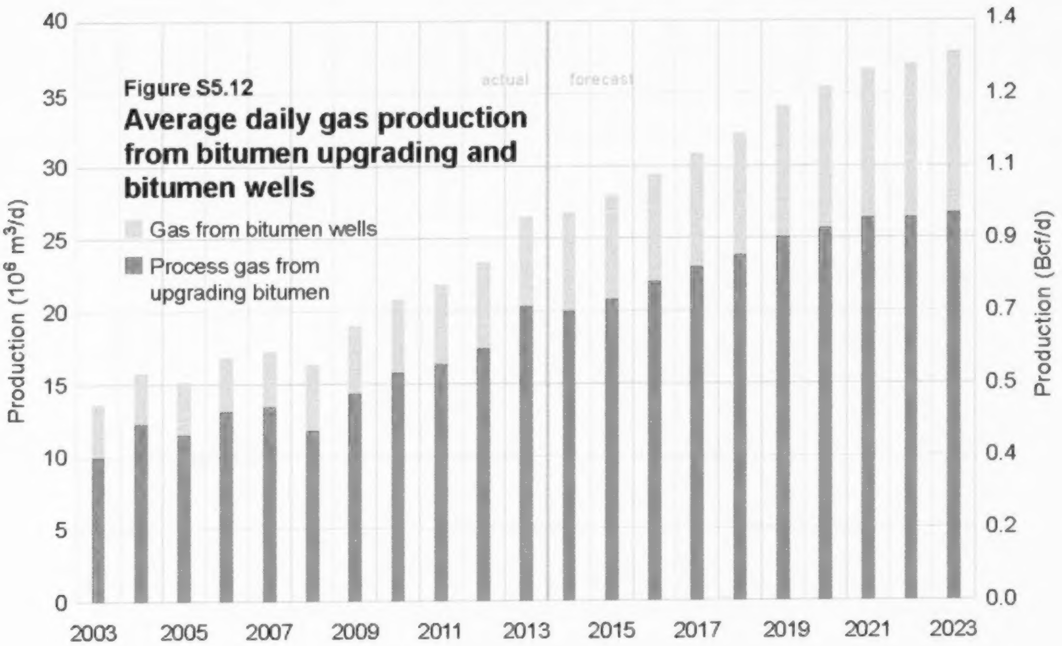


Figure S5.12
Average daily gas production from bitumen upgrading and bitumen wells

In 2013, about 20.3 10^6 m^3/d of process gas was generated at oil sands upgrading facilities, compared with a revised volume of 17.4 10^6 m^3/d in 2012. Process gas is primarily used as fuel, although increasing volumes are being sent to processing facilities for the removal of liquids. This number is expected to reach 26.7 10^6 m^3/d by the end of the forecast period. Natural gas production from primary and thermal bitumen wells increased by 0.3 10^6 m^3/d to 6.3 10^6 m^3/d in 2013 and is forecast to increase to 11.1 10^6 m^3/d by 2023. This gas is used mainly as fuel to create steam for on-site operations. Additional small volumes of gas are produced from primary bitumen wells and are used for local operations.

5.2.7 Commercial Natural Gas Storage

Commercial natural gas storage is used by the natural gas industry to provide short-term deliverability; the AER does not use volumes of commercially stored natural gas in projecting long-term production. Several pools in the province are being used for commercial natural gas storage to provide an efficient means of balancing supply with fluctuating market demand. Commercial natural gas storage is defined as the storage of third-party non-native gas; traditionally, it allows marketers to take advantage of seasonal price differences, effect custody transfers, and maintain reliability of supply. Natural gas from many sources may be stored at these facilities under fee-for-service, buy-sell, or other contractual arrangements. There are other gas storage schemes in the province that are not included in this category.

In the summer season, when demand is lower, natural gas is injected into these pools. As winter approaches, the demand for natural gas rises, injection slows or ends, and storage withdrawals generally begin at high withdrawal rates. Commercial natural gas storage pools, along with the operators and storage information, are listed in

Table S5.6. Ranchwest Energy Inc's Dimsdale Paddy A Pool received approval in January 2014 and, therefore, is not yet listed in **Table S5.6**.

In 2013, natural gas withdrawal for all storage schemes exceeded injections by 1463 10^6 m^3. This compares with 487 10^6 m^3 net injection in 2012. Alberta natural gas working volumes increased past the five-year high in August and remained high into the fall season as a result of toll changes on the TransCanada Corporation (TransCanada) Canadian Mainline Pipeline (Mainline) system. Alberta gas storage levels began to decrease in November with the start of the heating season. Withdrawals in December 2013 were 2459.2 10^6 m^3, significantly higher than the December 2012 level of 1116.3 10^6 m^3 due to the winter ice storm and freezing temperatures that affected parts of Manitoba, Ontario, Quebec, and the Atlantic provinces, increasing the demand for natural gas for heating purposes.

Marketable gas production volumes determined for 2013 were adjusted to account for the imbalance between volumes injected and volumes withdrawn from these storage pools. For the purpose of projecting future natural gas production, the AER assumes that injections and withdrawals are balanced for each year during the forecast period.

Figure S5.13 shows the location of existing gas storage facilities along the pipeline systems within Alberta.

Table S5.6 Commercial natural gas storage pools as of December 31, 2013

Field	Pool	Operator	Storage capacity (10^6 m^3)	Injection volumes, 2013 (10^6 m^3)	Withdrawal volumes, 2013 (10^6 m^3)
Brazeau River	Nisku E	Wild Rose Energy Ltd.	940	0	0
Carbon	Glauconitic	ATCO Midstream	1 127	951	1 049
Carrot Creek	Cardium CCC	Iberdrola Canada Energy Services Ltd.	986	319	445
Countess	Bow Island N & Upper Mannville M5M	Niska Gas Storage	1 552	574	816
Crossfield East	Elkton A & D	CrossAlta Gas Storage	1 197	560	921
Edson	Viking D	TransCanada Pipelines Ltd.	1 775	566	834
Hussar	Glauconitic R	Husky Oil Operations Ltd.	423	71	92
McLeod	Cardium D	Iberdrola Canada Energy Services Ltd.	282	183	221
Suffield	Upper Mannville I & K, and Bow Island N & BB & GGG	Niska Gas Storage	2 254	832	1 219
Warwick	Glauconitic-Nisku A	Warwick Gas Storage Inc.	881	600	521
Total			**11 417**	**4 655**	**6 119**
Difference					**-1 463**

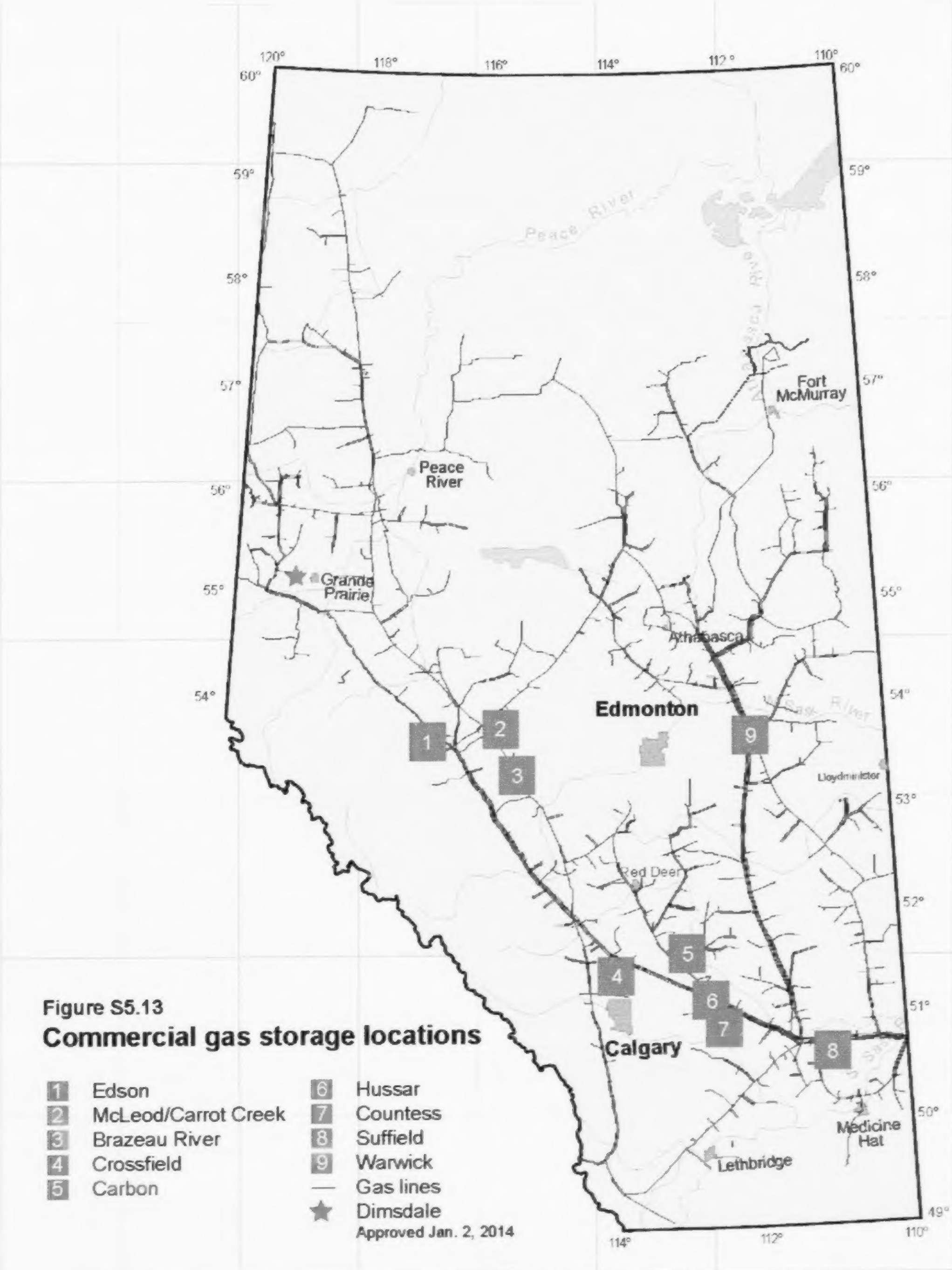


Figure S5.13
Commercial gas storage locations

5.2.8 Alberta Natural Gas Demand

The *Alberta Gas Resources Preservation Act* (first proclaimed in 1949) provides supply security for consumers in Alberta by "setting aside" large volumes of gas for their use before gas removals from the province are permitted. The act requires that when a company proposes to remove gas from Alberta, it must apply to the AER for a permit authorizing the removal. Removal of gas from Alberta is only permitted if the gas to be removed is surplus to the needs of Alberta's core consumers for the next 15 years. Core consumers are defined as Alberta residential, commercial, and institutional gas consumers who do not have alternative sustainable fuel sources.

The calculation in **Table S5.7** is done annually to determine what volume of gas is available for removal from Alberta after accounting for Alberta's future requirements. Using the 2013 remaining established reserves number, surplus natural gas is currently calculated to be 353 10^9 m^3. **Figure S5.14** illustrates historical "available for permitting" volumes.

Gas removals from Alberta have declined since 2001, from 311.5 10^6 m^3/d in 2001 to 141.3 10^6 m^3/d in 2013. Based on the AER's projection of gas production, this rate is forecast to drop to 53.8 10^6 m^3/d by 2023. This is higher than last year's projection of 49.3 10^6 m^3/d by 2022 mainly because this year's natural gas supply forecast is slightly higher.

The major natural gas pipelines in Canada that move Alberta gas to market are discussed in **Section 9.1.1.3** and illustrated in **Figure S5.15**, with export and provincial border points identified.

For Canadian ex-Alberta markets, historical demand growth and forecast supply are used in developing the demand forecasts. Export markets are forecast based on removal pipeline capacity available to serve such markets and on the recent historical trends in meeting that demand. The AER also reviews the projected demand for Alberta natural gas, focusing on intra-Alberta natural gas use.

Data from the Energy Information Administration (EIA) indicates that imports of natural gas from the United States have significantly risen in the past several years. This has been a result of increasing shale gas production in the United States, including natural gas production located close to eastern Canadian markets, typically served by western Canadian natural gas. Given the relatively close proximity to southern Ontario markets, producers and pipeline companies have proposed new pipeline projects that would carry natural gas sourced from the United States to Ontario markets.

Spectra, Enbridge, and DTE Energy recently announced the NEXUS Gas Transmission (NGT) system, which will deliver U.S. Appalachian shale gas to markets in the U.S. Midwest, Ohio, Michigan, and Ontario. The new pipeline will have the capacity to transport at least 28.2 10^6 m^3 per day of natural gas, will follow existing utility corridors to an interconnect in Michigan, and will use the existing Vector pipeline system to reach Ontario markets. The estimated in-service date is November 2015. The Iroquois Gas Transmission System, L.P., a limited partnership of five U.S. and Canadian energy companies, also recently announced a new pipeline project, the South-To-North Project (SoNo) that will deliver U.S. Marcellus natural gas supplies to TransCanada at Waddington, New York. The SoNo project will reverse flow on the Iroquois system, which will service eastern Canada and northern New England markets and have the capacity to transport 84.5 10^6 m^3/d. The proposed

Table S5.7 Estimate of gas reserves available for inclusion in removal permits as of December 31, 2013

	10^9 m^3 at 37.4 MJ/m^3
Reserves (as of year-end 2013)	
1. Total remaining established reserves	898
Alberta requirements	
2. Core market requirements	122
3. Contracted for noncore markets[a]	162
4. Permit-related fuel and shrinkage	24
Permit requirements	
5. Remaining permit commitments[b]	237
6. Total requirements	545
Available	
7. Available for removal permits	353

[a] For these estimates, 15 years of core market requirements and 5 years of noncore requirements were used.

[b] The remaining permit commitments are split 96 per cent under short-term permits and 4 per cent under long-term permits.

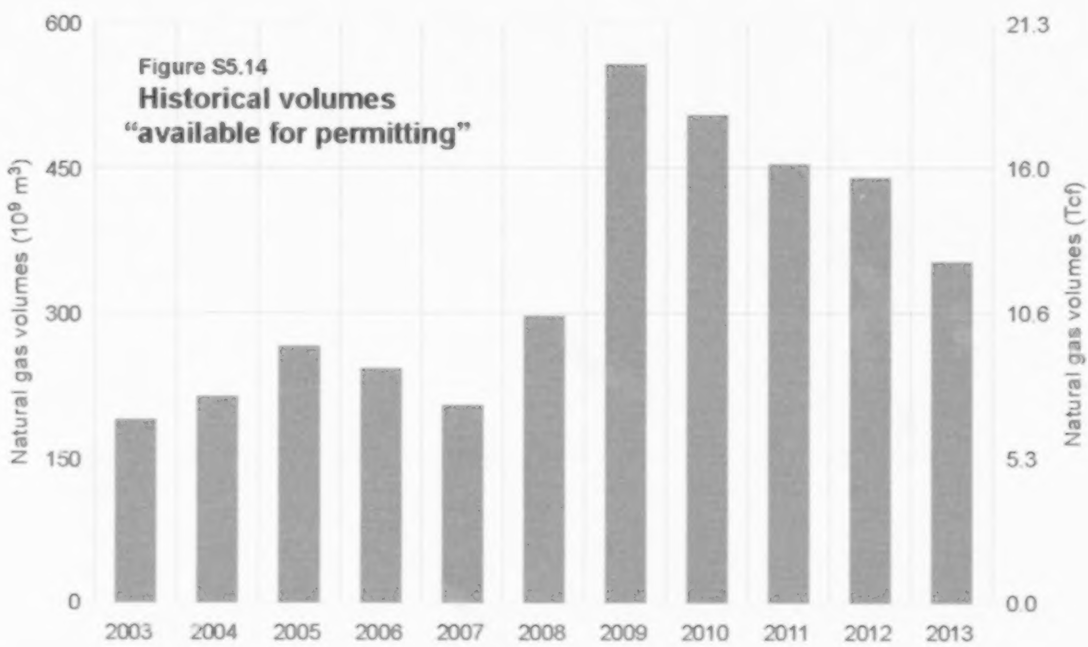


Figure S5.14
Historical volumes "available for permitting"

Figure S5.15
Major gas pipelines in Canada and Alberta border delivery and export points

project's in-service date is November 2016. For end-users in Ontario, gas sourced from the United States has the potential to be less expensive than gas sourced from western Canada.

Natural gas exports to the United States from Canada have been decreasing since 2007. However, each region in the United States is slightly different. At the Alberta-Saskatchewan border, deliveries to Empress have been in decline since 2007, whereas deliveries at McNeill have been gradually increasing over the same time. Deliveries at the Alberta-B.C. border have remained relatively flat.

Deliveries at Empress have been in decline as Alberta gas production has been decreasing due to lower gas prices, and record high natural gas production in the United States. TransCanada's Mainline pipeline system throughput volumes have also been in decline for the past several years.

In 2012, TransCanada reversed the flow of natural gas at the Niagara meter station on the Mainline system, which traditionally delivered Canadian natural gas to U.S. markets. End users in southern Ontario gained access to U.S. natural gas supplies for the first time. TransCanada also announced the conversion of one of the Mainline pipelines to a crude oil pipeline, the Energy East Pipeline Project, as natural gas volumes from western producers continue to fall.

Natural gas deliveries at McNeill have remained steady on the Foothills pipeline system serving the U.S. Mid-Continent, the Pacific Northwest, California, and Nevada. Deliveries at the Alberta-B.C. border are located closer to more active drilling regions of the province, such as PSAC Area 2. Natural gas deliveries on the Alliance pipeline have remained steady, carrying gas from Canada to the United States, connecting with the Alliance system near Chicago. The pipeline system was designed to transport natural gas liquids within the gas stream, which provides for a higher energy value or heat content. The U.S. portion of the Alliance pipeline delivers wet gas to Aux Sable's 59.2 10^6 m^3/d extraction and fractionation plant at Channahon, Illinois, where specification NGL products (ethane, propane, normal butane, isobutane, and natural gasoline) can be extracted and fractionated.

A potential source of competition for U.S. natural gas could come from the numerous proposed liquefied natural gas (LNG) export projects in the United States that would source gas from prolific shale gas plays. As of early 2014, the U.S. Federal Energy Regulatory Commission (FERC) lists that 13 export terminals have been proposed, with an additional 12 potential U.S. sites identified by project sponsors. Only two proposed LNG export projects are to be located on the U.S. West Coast. In addition, EIA data indicates that in 2012, U.S. natural gas exports to Mexico were 16.9 10^9 m^3/d. The EIA expects exports to Mexico to grow by 6 per cent per year.

Figure S5.16 illustrates the breakdown of marketable natural gas demand in Alberta by sector.

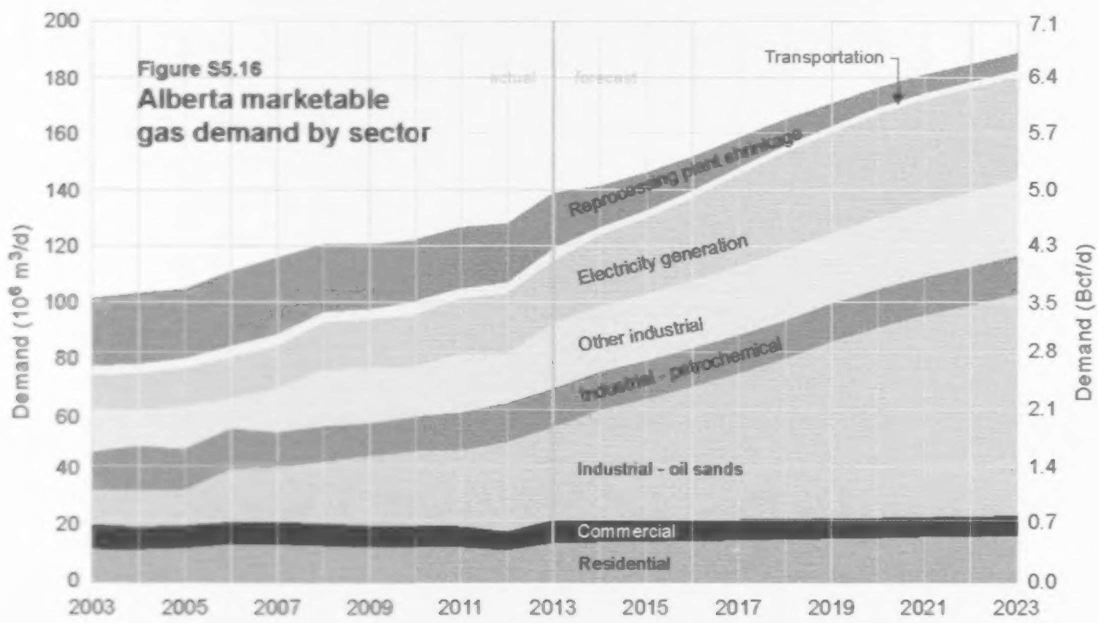


Table S5.8 Average use rates of purchased gas for oil sands operations, 2013[a]

	Excluding purchased gas for cogeneration		Including purchased gas for cogeneration	
Extraction method	(m^3/m^3)	(mcf/bbl)[b]	(m^3/m^3)	(mcf/bbl)
In situ				
SAGD	143	0.8	206	1.16
CSS	143	0.8	192	1.08
Mining with upgrading	80	0.45	115	0.64

[a] Expressed as cubic metres of natural gas per cubic metre of upgraded or nonupgraded bitumen production. Rates are an average of typical schemes with sustained production.

[b] Million cubic feet per barrel.

Residential gas requirements are expected to grow moderately at an average annual rate of 1.8 per cent over the forecast period as improvements in energy efficiency prevent household energy use from rising significantly.

Commercial gas demand in Alberta has declined gradually since 2003 and is expected to continue to decline at an average annual rate of 1.4 per cent per year over the forecast period. This is largely due to gains in energy efficiency and a shift towards electricity.

The electricity-generating industry will require increased volumes of natural gas to fuel new industrial on-site and gas-fired generation plants expected to come on stream over the forecast period. Natural gas requirements for electricity generation are expected to increase from about 22.3 10^6 m^3/d in 2013 to 36.8 10^6 m^3/d by 2023. The projected increase in gas demand in this sector is due to the assumption that gas will be the preferred feedstock for new power plants.

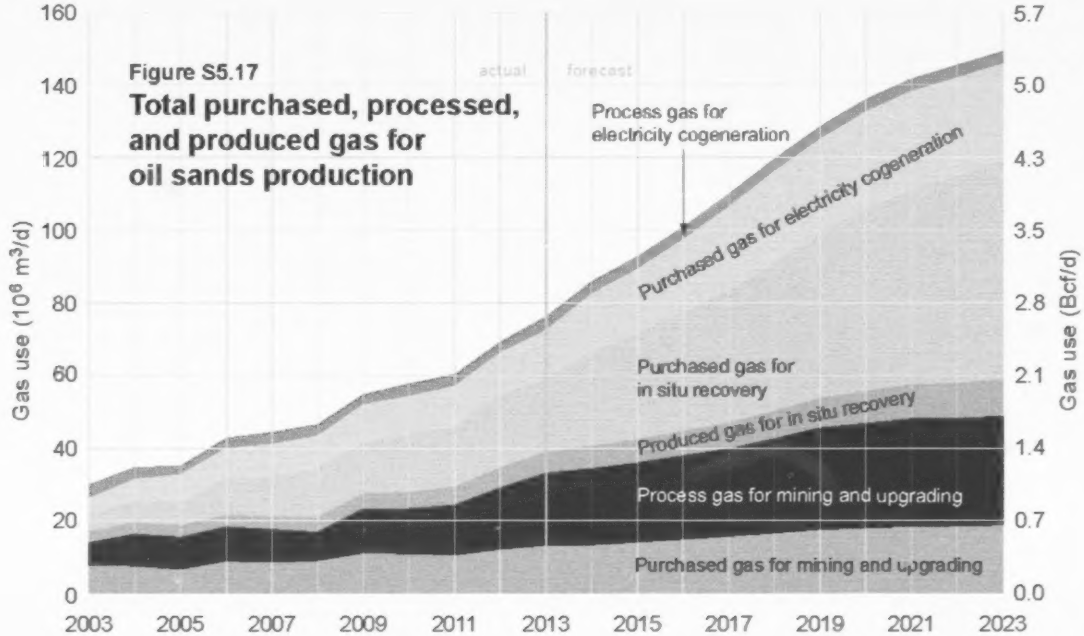
Another significant increase in Alberta demand is due to projected development in the industrial sector. Gas demand for oil sands operations[5] will increase from 33.2 10^6 m^3/d in 2013 to 78.9 10^6 m^3/d in 2023. **Table S5.8** outlines the average purchased gas use rates for oil sands operations. Gas production from and demand for the oil sands operations are sourced from PETRINEX.

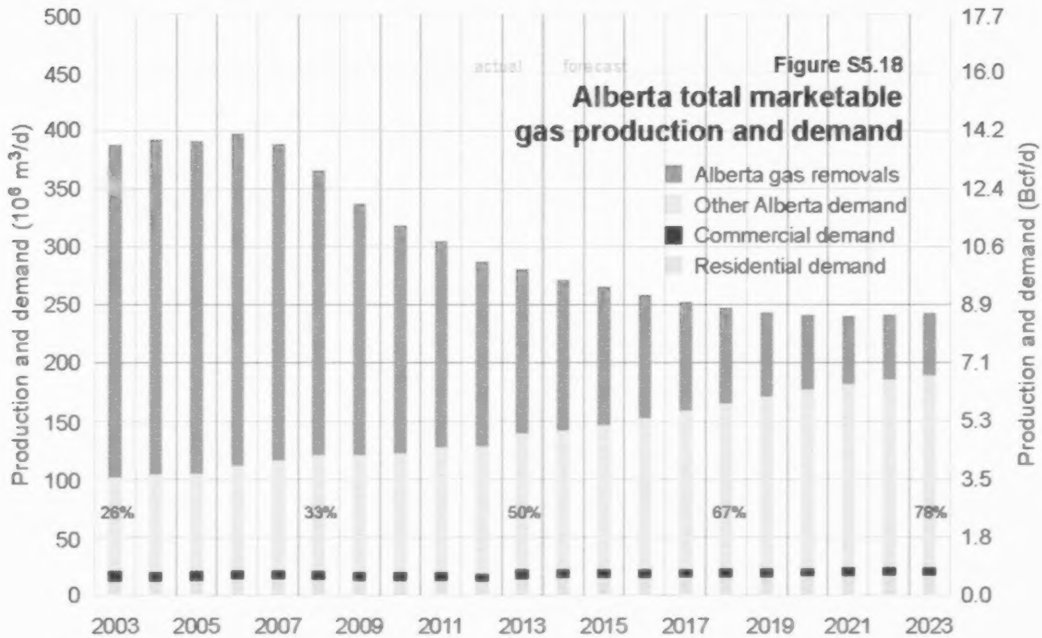
As noted earlier, oil sands upgrading operations produce process gas that is used on site. The in situ operations also produce solution gas from bitumen wells. **Figure S5.17** shows total gas use by the oil sands sector, including gas used for in situ recovery, mining and upgrading, and electricity cogeneration. The gas supply sources include purchased gas (purchased from outside the scheme for bitumen recovery), process gas (produced from the upgrading of bitumen that contains large volumes of natural gas liquids and olefins), and produced gas (from crude bitumen wells). Gas use by the oil sands sector was 76.32 10^6 m^3/d in 2013 and is forecast to increase to 149.29 10^6 m^3/d by 2023.

Figure S5.18 shows total Alberta natural gas demand and production. Natural gas produced from bitumen wells or from bitumen upgrading is considered to be used on site and is not included as marketable production available to meet Alberta demand. Therefore, gas removals from the province represent natural gas production from conventional and CBM production (and do not include imports from B.C.) minus Alberta demand.

[5] Gas demand for oil sands electricity cogeneration is categorized under industrial oil sands demand.

In 2013, demand within Alberta was 138.9 10^6 m^3/d, which represented 50.0 per cent of the total Alberta natural gas production. The remainder was sent to other Canadian provinces and the United States. By the end of the forecast period, demand is projected to reach 188.8 10^6 m^3/d, or 77.8 per cent of total Alberta production. However, the forecast does not include any potential shale gas production that may occur in Alberta. Additionally, natural gas supply from British Columbia that moves through Alberta to market is not included in this analysis. The B.C. supply is expected to increase over the forecast period and provide Alberta with an additional source of natural gas if needed.





6 NATURAL GAS LIQUIDS

HIGHLIGHTS

About 75 per cent of the total ethane in the natural gas stream was extracted in 2013, compared with 70 per cent in 2012 and 68 per cent in 2011.

In 2013, ethane volumes extracted from conventional natural gas at Alberta processing facilities increased 6 per cent from 2012.

Propane, butane, and pentanes plus production increased by 4 per cent, 5 per cent, and 9 per cent, respectively, in 2013.

Produced natural gas is primarily methane, but it also contains heavier hydrocarbons consisting of ethane (C_2), propane (C_3), butanes (C_4), and pentanes and heavier hydrocarbons (typically referred to as pentanes plus or C_5+), all of which are referred to as natural gas liquids (NGLs). Natural gas also contains water and contaminants such as carbon dioxide (CO_2) and hydrogen sulphide (H_2S). In Alberta, the production of all ethane, pentanes plus, and most propane and butanes are from the raw natural gas stream. Most of the NGL supply is recovered from the processing of natural gas at gas plants, although some pentanes plus is recovered as condensate at the field level and sold as product. Other sources of NGLs are crude oil refineries, where small volumes of propane and butanes are recovered, and from gases produced as by-products of bitumen upgrading called off-gas. Off-gas is a mixture of hydrogen and light gases, including ethane, propane, and butanes. Most of the off-gas produced from oil sands upgraders is currently being used as fuel for oil sands operations. Coalbed methane (CBM) is generally dry gas, so it is not expected to contribute to future NGL reserves. Shale gas appears to have a wide range of liquids content, from lean to liquids-rich. Consequently, depending on development trends, shale gas may contribute significantly to the province's NGL reserves in the future.[1]

The AER estimates remaining reserves of NGLs based on volumes expected to be recovered from remaining raw natural gas using existing technology and projected market conditions, which are described in **Section 6.2.1**. Initial reserves for NGLs are not calculated since historically only a fraction of the liquid volume that could have been extracted was recovered, and much was flared for lack of market demand. The AER's projections for the overall recovery of each NGL component are explained in **Section 5.1.3.5**. As shown graphically in **Figure R5.8**, the estimate of the reserves of liquid ethane is based on the assumption that 65 per cent of the total raw ethane gas reserves will be extracted from the natural gas stream, while 85 per cent of propane, 90 per cent of butane, and 100 per cent of pentanes plus are assumed extracted from the gas stream. Although it is reasonable to expect that some heavier liquids will drop out in the reservoir as pressure declines with depletion and will not be recovered, the AER's calculations assume that the

[1] A trend may be developing in Alberta with respect to the content of in-place and/or extractable volumes of NGLs in "tight" conventional and unconventional reservoirs. Conventional reservoirs generally hold a relatively well understood range of NGL content from lean to wet. Some tight conventional reservoirs and at least some unconventional reservoirs may produce unusually high levels of NGLs making them "liquids-rich." The AER is following this development and may review its NGL reserve calculation process as appropriate.

composition of raw produced gas remains unchanged over the life of a pool because it is difficult to predict and the volume is not expected to be significant. The NGL reserves expected to be removed from natural gas are referred to as extractable reserves, and those not expected to be recovered are included as part of the province's natural gas reserves, as discussed in **Section 5.1**.

6.1 Reserves of Natural Gas Liquids

6.1.1 Provincial Summary

Estimates of the remaining established reserves of extractable NGLs in 2013 are summarized in **Tables R6.1** and **R6.2**. **Figure R6.1** shows remaining established reserves of extractable NGLs compared with 2013 production.

Table R6.1 Established reserves and production change highlights of extractable NGLs (10^6 m^3 liquid)[a]

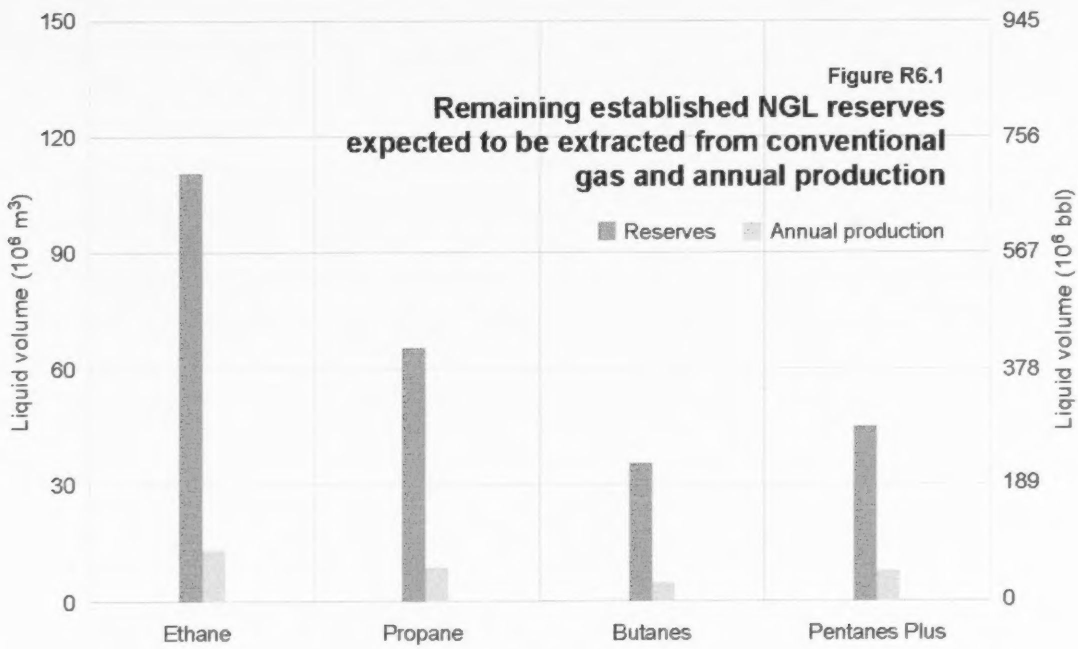
	2013	2012	Change
Cumulative net production			
Ethane	331.1	318.0	+13.1
Propane	311.9	303.4	+8.5
Butanes	177.4	172.8	+4.6
Pentanes plus	374.2	366.6	+7.6
Total	**1 194.6**	**1 160.8**	**+33.8**
Remaining established reserves (expected to be extracted)			
Ethane	110.5	108.1	+2.4
Propane	65.5	63.7	+1.8
Butanes	35.4	34.6	+0.8
Pentanes plus	44.9	45.5	-0.6
Total	**256.3**	**252.0**	**+4.3**
	(1 617 10^6 bbl)[b]	**(1 590 10^6 bbl)[b]**	
Annual production	**33.8**	**32.2**	**+1.6**

[a] 10^6 m^3 = million cubic metres.

[b] bbl = barrels.

Table R6.2 Reserves of NGLs as of December 31, 2013 (10^6 m^3 liquid)

	Ethane	Propane	Butanes	Pentanes plus	Total
Total NGLs in remaining raw gas	168.6	77.0	39.3	44.9	329.9
Liquids expected to remain in dry marketable gas	58.2	11.6	3.9	0.0	73.7
Remaining established reserves recoverable from					
Field plants	44.0	38.5	23.6	40.4	146.5
Straddle plants	66.5	27.0	11.8	4.5	109.7
Total	**110.5**	**65.5**	**35.4**	**44.9**	**256.3**



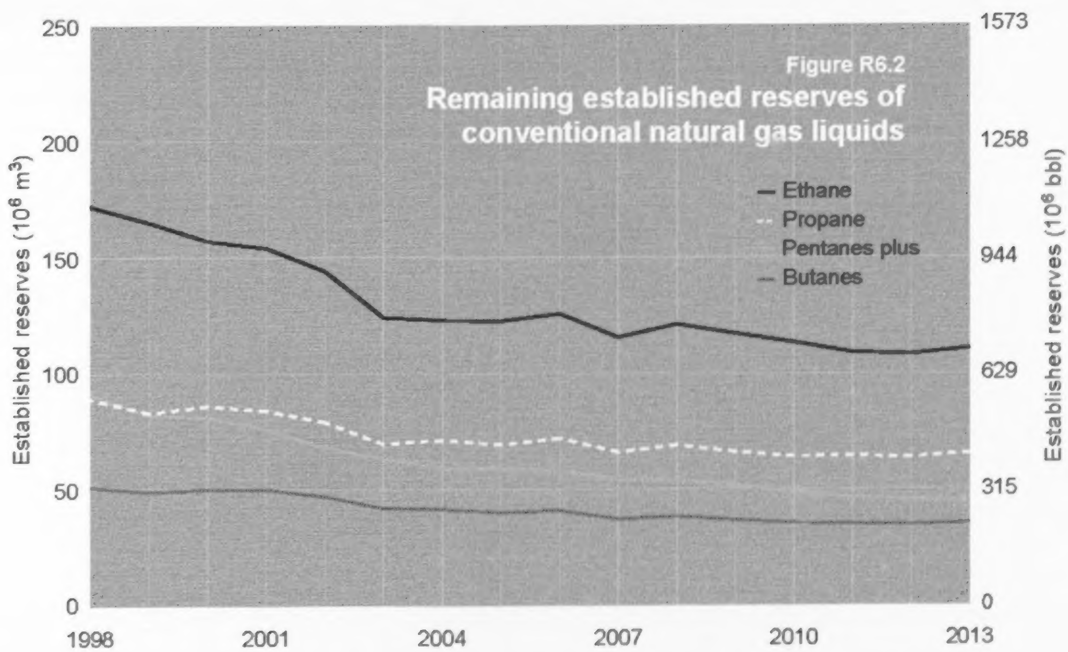
Total remaining reserves of extractable NGLs have increased by 1.7 per cent compared with 2012 due to an increase in the development of pools that are more liquids rich. Fields that have contributed significantly to this increase are Ferrier, Kakwa, Pouce Coupe, Sundance, and Wapiti. These fields and others containing large NGL volumes are listed in **Appendix B**, **Table B.6** and **Table B.7**.

6.1.2 Ethane

As of December 31, 2013, the AER estimates remaining established reserves of extractable ethane to be 110.5 million (10^6) cubic metres (m^3) in liquefied form. Of that, 44.0 10^6 m^3 is expected to be recovered from field plants and 66.5 10^6 m^3 from straddle plants that deliver gas outside the province, as shown in **Table R6.2.** It is estimated that 6.1 10^6 m^3 is recoverable from the ethane component of solvent injected into pools under miscible flood to enhance oil recovery. At the end of 2013, only the following five pools were still actively injecting solvent: Rainbow Keg River B, Rainbow Keg River F, Judy Creek Beaverhill Lake A, Swan Hills Beaverhill Lake A&B, and Black Keg River A.

Thirty-five per cent of the total raw ethane, or 58.2 10^6 m^3 (liquid), is estimated to remain in the marketable gas stream and could potentially be recovered. **Figure R6.2** shows the remaining established reserves of ethane declining rapidly from 1996 to 2003, then levelling off as more ethane is extracted from raw gas. In 2013, the extraction of specification ethane was 13.1 10^6 m^3, compared with 12.5 10^6 m^3 in 2012.

For individual gas pools, the ethane content of gas in Alberta varies considerably, falling within the range of 0.0025 to 0.20 moles per mole (mol/mol). As shown in **Appendix B**, **Table B.6**, the volume-weighted average ethane content of all remaining raw gas is 0.052 mol/mol. Also listed in this table are ethane volumes recoverable



from fields containing the largest ethane reserves. Of these fields, the ten largest—in alphabetical order, Ansell, Elmworth, Kakwa, Kaybob South, Pembina, Sundance, Rainbow, Wapiti, Wild River, and Willesden Green—account for 34 per cent of the total ethane reserves but only 22 per cent of remaining established marketable gas reserves.

6.1.3 Other Natural Gas Liquids

As of December 31, 2013, the AER estimates remaining extractable reserves of propane, butanes, and pentanes plus to be 65.5 10^6 m^3, 35.4 10^6 m^3, and 44.9 10^6 m^3, respectively. The breakdown in the liquids reserves at year-end 2013 is shown in **Table R6.2**. **Table B.7** in **Appendix B** lists propane, butanes, and pentanes plus reserves in fields containing the largest remaining liquids reserves. The ten largest of these fields—in alphabetical order, Ansell, Brazeau River, Kakwa, Kaybob South, Pembina, Rainbow, Sundance, Wapiti, Wild River, and Willesden Green—account for about 30 per cent of the total propane, butanes, and pentanes plus liquid reserves. The volumes recoverable at straddle plants are not included in the field totals but are shown separately at the end of the table.

6.1.4 Ultimate Potential

The remaining ultimate potential of liquid ethane is determined based on projected market demand and the volumes that could be recovered as liquid from the remaining ultimate potential of natural gas using existing cryogenic technology. The percentage of ethane volumes that have been extracted have been generally increasing over time. In 2013, there was a substantial increase for the fifth year in a row as the percentage recovered was 75 per cent, up from 70 per cent in 2012, 68 per cent in 2011, and 63 per cent in 2010. The AER estimates that

70 per cent of the remaining ultimate potential of ethane gas will be extracted. Based on a remaining ethane gas ultimate potential of 105 billion (10^9) m^3, the AER estimates the remaining ultimate potential of liquid ethane to be 262 10^6 m^3. The other 30 per cent, or 32 10^9 m^3, of ethane gas is expected to be sold for its heating value as marketable natural gas.

For liquid propane, butanes, and pentanes plus combined, the remaining ultimate potential is 315 10^6 m^3. This assumes that the remaining ultimate potential as a percentage of the initial ultimate potential is similar to that of conventional marketable gas—about 28 per cent.

Additionally, 9301 10^6 m^3 of unconventional, in-place NGLs in six key shale formations in Alberta have been identified by the shale- and siltstone-hosted hydrocarbon resources study discussed in **Section 2.2.2**. This very large resource represents a huge potential for future development, but the technical, economic, environmental, and social constraints on recoverability were not included in the study.

As discussed in **Section 2.3.3**, a joint government report was released in 2013 on the ultimate potential of one of the major shale- and siltstone-hosting hydrocarbon units in Alberta, the Montney Formation. The report estimated that from the 4863 10^6 m^3 of expected in-place NGLs, some 298 10^6 m^3 might ultimately be recovered. If similar results were to be estimated in the other formations, the increase to the ultimate potential of NGLs in Alberta could be substantial.

6.2 Supply of and Demand for Natural Gas Liquids

In forecasting ethane and other NGLs, the AER recognizes that NGL content, gas plant recovery efficiencies, NGL prices, and gas production volumes from remaining established reserves and future gas reserves additions affect future production. For ethane, demand also plays a major role in future extraction. In the short term, and possibly longer term, the NGL content from new gas reserves is expected to be more liquids rich than existing reserves. In the future, ethane and other gas liquids extracted from oil sands off-gas will supplement supplies from conventional gas production and will be needed to meet the forecast ethane demand.

Ethane and other NGLs are recovered mainly from the processing of natural gas. Field gas processing facilities ensure that natural gas meets the quality specifications of the rate-regulated natural gas pipeline systems, which may require removal of NGLs to meet pipeline hydrocarbon dew point specifications.[2] Removal of other gas contaminants, such as H_2S and CO_2, is also required. Field plants generally recover additional volumes of NGLs—more than what is required to meet pipeline specifications, depending on the plant's extraction capability—to obtain full value for the NGL components. Generally, the heavier NGLs (butanes and pentanes plus) are removed at field plants. Field plants may send recovered NGL mix to centralized, large-scale fractionation plants where the mix is fractionated into specification products. Liquids that are heavy enough to be naturally collected at the field level due to the drop in pressure and temperature are called condensate.

[2] The dew point is the temperature at which hydrocarbon molecules condense out of the gaseous phase.

The properties of condensate and pentanes plus are similar, and the terminology is often used interchangeably as both are marketed in the same way in western Canada.

Gas reprocessing plants, often referred to as straddle plants, recover NGL components or NGL mix from marketable gas. They are usually located on rate-regulated main gas transmission pipelines at border delivery points. Straddle plants remove much of the propane plus (C_3+) and ethane volumes, with the degree of recovery being determined by the plant's extraction capability, contractual arrangements, and product demand. **Figure S6.1** illustrates the stages involved in processing raw gas and crude oil for the recovery of ethane, propane, butanes, and pentanes plus.

Figure S6.2 shows the pipeline systems that move ethane and ethane plus (C_2+) mix NGLs from the processing plants to the markets. Gas processing plants capable of extracting C_2+ mix NGLs are typically tied to C_2+ mix NGL gathering systems that move liquids to NGL fractionators in the Fort Saskatchewan area. Ethane recovered at field processing plants, NGL fractionators, and the straddle plants is shipped on the Alberta ethane gathering system to the Alberta ethane market.

6.2.1 Ethane and Other Natural Gas Liquids Production – 2013

In Alberta, there are about 495 active gas processing plants that recover NGL mix or specification products, 10 fractionation plants that fractionate NGL mix streams into specification products, and 9 straddle plants.

Recovery efficiencies of NGL specification products at field plants depend on plant design and economics and generally range from 75 to 98 per cent for propane, 90 to 100 per cent for butanes, and 98 to 100 per cent for pentanes plus. A few field plants are also capable of extracting ethane as a specification product or as a C_2+ mix and are referred to as deep-cut facilities.

Ethane recovery at straddle plants varies from 40 to 90 per cent and averages 65 per cent. The average percentages of propane, butanes, and pentanes plus recovered at Alberta straddle plants are 98.5, 99.5, and 99.8, respectively. **Table S6.1** outlines information for 2013 about the straddle plants operating in Alberta, including the plant location, operator name, approved natural gas throughput volumes, natural gas receipts (actual throughput volumes), and the volume of specification ethane recovered (unless otherwise noted).

In 2013, ethane volumes extracted at Alberta processing facilities increased 5.5 per cent to 35.9 thousand (10^3) m^3/d from 34.0 10^3 m^3/d in 2012. About 75 per cent of total ethane in the gas stream was extracted in 2013, while the remainder was left in the gas stream and sold for its heating value. **Table S6.2** shows the volumes of specification ethane extracted at the three types of processing facilities during 2013. This table excludes less than 0.1 10^3 m^3/d of ethane produced from off-gas in 2013.

The C_2+ mix NGLs shipped from British Columbia to the Redwater fractionation plant for fractionation into specification products are included in Alberta production volumes.

Since 2007, gas receipts at Alberta straddle plants have been in decline, negatively affecting the amount of NGLs recovered at these facilities. Ethane recovered at straddle plants has decreased by 15.3 per cent since 2007.

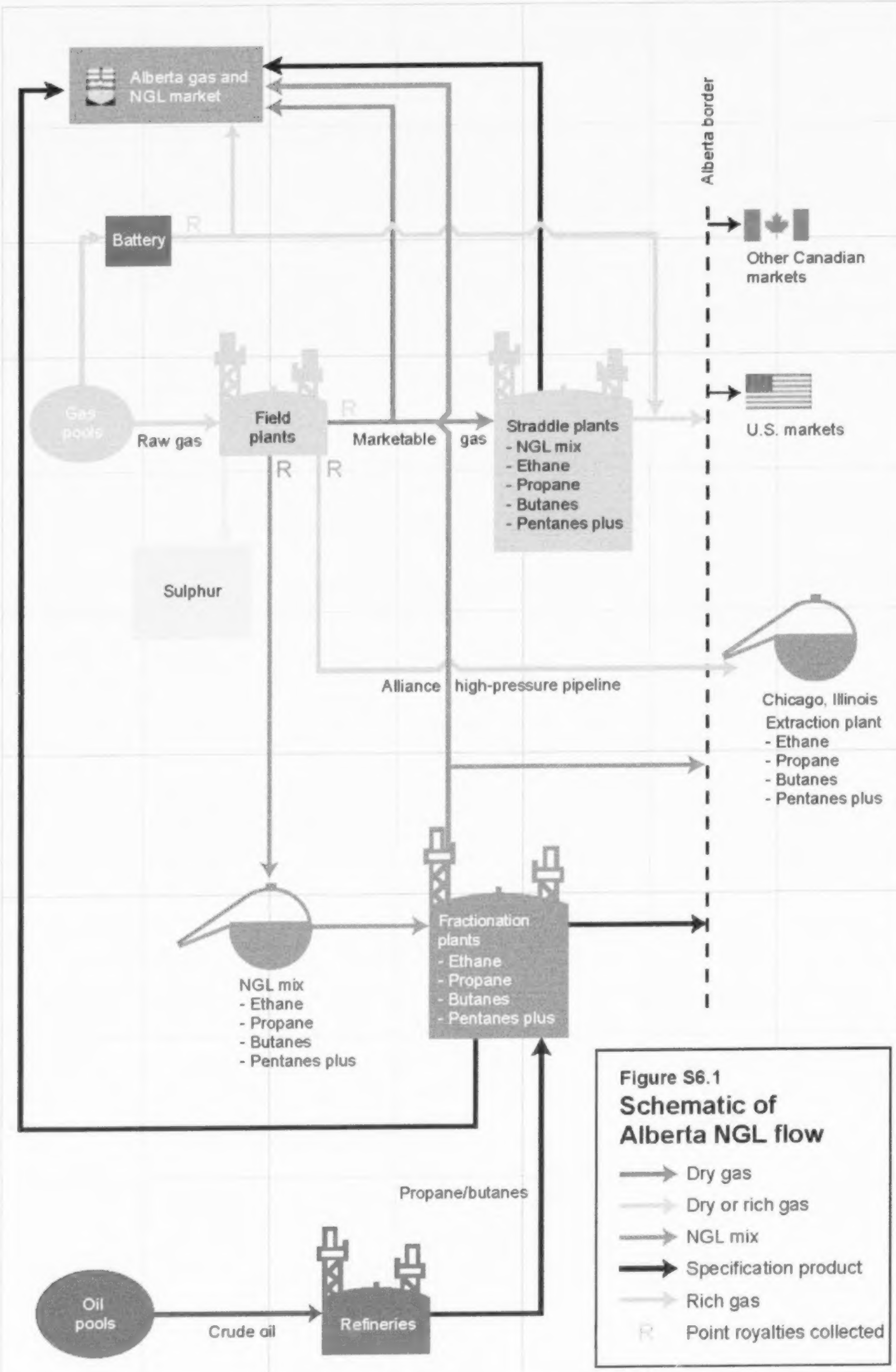


Figure S6.1
Schematic of Alberta NGL flow

Figure S6.2
Ethane gathering and delivery systems

Table S6.1 Straddle plants in Alberta, 2013

Area	Location	Operator	Approved gas volumes (10^3 m^3/d)	Gas receipts (10^3 m^3/d)	Ethane production (m^3/d)
Empress	10-11-020-01W4M	Spectra Energy Empress Management	67 960	34 697	3 786
Empress	04-12-020-01W4M	Plains Midstream Canada ULC	176 750	42 375	6 246
Cochrane	16-16-026-04W5M	Inter Pipeline Extraction Ltd.	70 450	47 807	7 513
Ellerslie (Edmonton)	04-04-052-24W4M	AltaGas Ltd.	11 000	8 917	1 691
Empress	01-10-020-01W4M	ATCO Energy Solutions Ltd.	31 000	11 060	793
Fort Saskatchewan[a]	02-03-055-22W4M	ATCO Energy Solutions Ltd.	1 051	668	0
Empress	16-02-020-01W4M	1195714 Alberta Ltd.	33 809	28 217	4 085
Joffre (JEEP)	03-29-038-25W4M	AltaGas Ltd.	7 066	302	810
Atim[a] (Villeneuve)	08-05-054-26W4M	ATCO Energy Solutions Ltd.	1 133	928	0
Total			**400 219**	**174 971**	**24 924**

[a] These plants are approved to recover a C_2+ mix and not specification ethane.

Table S6.2 Ethane extraction volumes at gas plants in Alberta, 2013

Gas plants	Volume (10^3 m^3/d)	Percentage of total
Field plants	2.6	7.1
Fractionation plants	7.9	22.1
Straddle plants	25.4	70.8
Total	**35.9**	**100.0**

In 2007, ethane extracted at straddle plants represented 76 per cent of total ethane production, whereas ethane recovered at field plants and fractionation plants represented 5 and 19 per cent, respectively. In 2013, ethane extracted at straddle plants was up 1.4 per cent over 2012, but only represented about 71 per cent of total ethane extraction volumes.

Ethane extracted at field plants in 2013 increased by 15.9 per cent over 2012 and represented 7 per cent of total ethane extracted. Ethane extracted at field plants has been on the rise over the last several years and has increased by 19.8 per cent since 2007. Ethane recovered at fractionation plants in 2013 was up 18.4 per cent, and represented 22 per cent of total ethane extracted in 2013. Overall ethane production was up over 2012 levels due to volumes extracted by field plants and recovered at fractionation plants as a result of new deep-cut projects and increased ethane content in the gas stream.

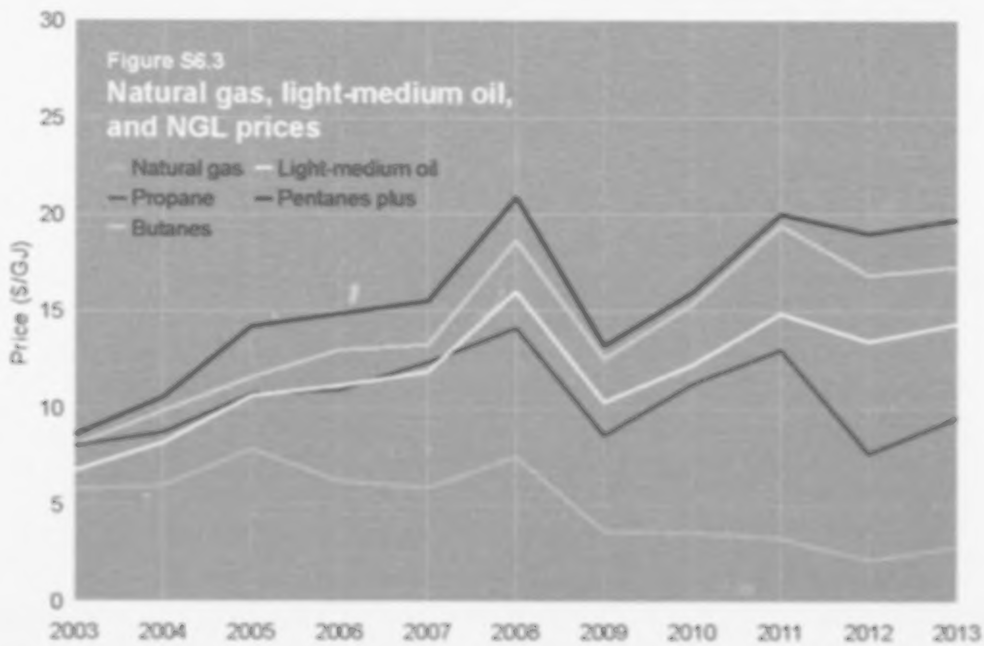
As a result of wetter raw gas production from PSAC Areas 2, 5, and 7, and NGL infrastructure development in late 2012 and 2013, propane, butane, and pentanes plus production increased over 2012 levels. Propane

production increased by 3.6 per cent in 2013 to 23.4 10^3 m^3/d, compared to 22.6 10^3 m^3/d in 2012. From 2007 to 2011, propane production declined from 25.6 10^3 m^3/d in 2007 to 21.6 10^3 m^3/d in 2011, then began to increase in 2012. Growth in propane production in 2012 and 2013 is attributed to increased extraction volumes from field plants and fractionation plants.

Butanes rose by 5.4 per cent from 12.0 10^3 m^3/d in 2012 to 12.6 10^3 m^3/d in 2013. Although butane production increased in 2013, overall butane production is down 8.9 per cent since 2007. Pentanes plus production rose by 9.0 per cent in 2013 over 2012. In 2013, 20.8 10^3 m^3/d of pentanes plus were produced compared with 19.1 10^3 m^3/d in 2012. Since 2007, pentanes plus production has decreased by 10.9 per cent. Butane and pentanes plus extracted at field and fractionation plants increased in 2013 whereas volumes extracted at straddle plants decreased.

Production from PSAC Area 2, an area with wet to liquids-rich gas, held relatively steady, only slightly decreasing compared to all the other PSAC areas. This area has the largest remaining extractable liquids reserves in the province. Production from PSAC Area 3, known for its dry gas production, experienced an 18.1 per cent decrease in production. In 2013, conventional natural gas production in the province decreased by 2.5 per cent. The shift by industry to develop pools with higher natural gas liquids is expected to continue over the forecast period.

Figure S6.3 shows the historical natural gas and liquids prices in Canadian dollars per gigajoule ($/GJ). The figure shows that propane, butanes, and pentanes plus prices follow the light-medium crude oil price. The value that producers are receiving for liquids content in the gas stream is still driving natural gas drilling in liquids-rich areas of the province.



6.2.2 Ethane and Other Natural Gas Liquids – Recent Developments

As conventional gas production declines, less ethane will be available for use by the petrochemical sector. To address the tight supply of ethane in Alberta, the provincial government implemented its Incremental Ethane Extraction Policy (IEEP) in 2006 and amended and extended it in 2011. The policy, initially designed to encourage extraction of ethane from natural gas, has been revised to also encourage ethane extraction from off-gases that result from bitumen upgrading or refining. Alberta's petrochemical industry is the largest in Canada and depends on the availability of competitively priced ethane to remain viable.

The province's IEEP is in effect until December 31, 2016. Fractionation credits are provided to petrochemical companies that consume incremental ethane for value-added upgrading, in Alberta, to ethylene and derivatives. The credit is owned by the company that consumes the ethane or ethylene and can be sold to either a natural gas or bitumen royalty payer to be applied against its royalty obligation.

Eight IEEP projects have been approved to date, and eight new projects were submitted by petrochemical companies in 2012. The latter represents a significant increase compared with the four projects submitted in 2011. The 2013 IEEP projects are listed in **Table S6.3**.

There are several key determinants that must be factor in deciding when to build NGL facilities: the location to raw gas production, the liquids content of the raw gas stream, existing infrastructure, and the proximity to markets. Below are recent developments and announcements from the NGL industry in Alberta.

Table S6.3 IEEP projects as of December 31, 2013

Feedstock type	Date approved	Project name	Company	Submission year
Conventional	April 14, 2008	Empress V Deep Cut - IPF/Dow	Dow	2008
Conventional	April 14, 2008	Rimbey Ethane Extraction - Keyera/Dow	Dow	2008
Conventional	Sept 14, 2010	Hidden Lake Streaming - TCPL/NOVA	Nova	2010
Off-gas	Sept 14, 2010	Williams Off-Gas Ethane Extraction	Nova	2010
Conventional	Dec 7, 2011	Musreau Deep Cut	Dow	2011
Conventional	July 26, 2011	Shell Waterton Incremental NGL Recovery	Shell	2011
Off-gas	July 26, 2011	Scotford Fuel Gas Recovery (Refinery)	Shell	2011
Conventional	Aug 28, 2013	Harmattan Plant Costream	Nova	2011
Conventional	Submitted	Shell Jumping Pound	Shell	2012
Off-gas	Submitted	Shell Scotford Upgrader Off-Gas	Shell	2012
Off-gas	Submitted	Williams Off-Gas Ethane Extraction (Incremental)	Nova	2012
Conventional	Submitted	AltaGas Gordondale Deep Cut	Nova	2012
Conventional	Submitted	Judy Creek Ethane Extraction	Nova	2012
Conventional	Submitted	Resthaven Facility Phase 1	Dow	2012
Conventional	Submitted	Rimbey Turbo Expander	Dow	2012
Conventional	Submitted	Project Turbo (Saturn Plant)	Dow	2012

Source: Alberta Department of Energy

Williams Companies Inc. (Williams) receives a large portion of the off-gas produced at Suncor's upgrading facility in the Fort McMurray area and extracts C_3+ mix NGLs and olefins at its Fort McMurray liquids extraction plant. NGLs and olefins production was 1798 m^3/d in 2013, down from 2054 m^3/d in 2012. Williams then sends the liquid mix from Fort McMurray to its Redwater fractionation plant near Edmonton through the Boreal pipeline, which started operating in 2012.

Williams entered into a long-term agreement with Canadian Natural Resources Ltd. (CNRL) to capture the off-gas produced from its upgrader at its Horizon project and to extract up to 1907 10^3 m^3/d by mid-2015, growing to 2384 10^3 m^3/d of NGLs and olefins by 2018.

In 2013, the Boreal pipeline started shipping C_2+ mix NGLs and olefins as ethane and ethylene fractionation capacity was added at Williams's Redwater fractionation plant. Williams will extend the Boreal pipeline to the proposed liquids extraction plant adjacent to CNRL's upgrader.

In 2013, Williams approved the construction of a propane dehydrogenation (PDH) facility at Redwater that will produce polymer grade propylene, adding value to propane in Alberta. The PDH facility will be the first and only facility of its kind in Canada and is expected to be operational in the second quarter of 2017 and will require about 3492 m^3/d of propane. The feedstock for the project will come from off-gases produced by Suncor and CNRL.

Aux Sable's Heartland off-gas processing plant started operating in 2011. This processing plant receives off-gas from Shell's Scotford upgrader and refinery and extracts ethane, a C_3+ mix, and hydrogen. Total liquids production was 69 m^3/d in 2013, up from 55 m^3/d in 2012. The ethane is shipped on the Alberta ethane gathering system to meet petrochemical demand. The C_3+ mix and hydrogen is shipped back to Shell's facilities for their refining operations.

Aux Sable recently announced that they will be filing an application in 2014 to export up to 169.0 10^6 m^3/d of expected liquids-rich natural gas sourced from the Montney and Duvernay formations. The gas will be shipped to Aux Sable's extraction and fractionation plant at Channahon, Illinois.

Nova Chemicals signed an agreement to purchase and transport ethane produced at the Tioga gas plant in North Dakota via a new pipeline to Alberta. This new pipeline (Vantage) was approved by the National Energy Board (NEB) in 2012 and was commissioned in early 2014.

A deep-cut facility at the Musreau gas processing plant operated by Pembina Pipeline Corporation (Pembina) started operating in February 2012, and the expansion of its shallow-cut facility at this site came on stream in September 2012. Pembina plans to construct, own, and operate a C_3+ plant, Musreau II, capable of processing about 3 10^6 m^3/d of natural gas with a yield of about 667 m^3/d near its existing Musreau facility. The C_3+ mix would be transported on Pembina's conventional pipeline and is expected to be in service in the first quarter of 2015.

Pembina's Saturn I deep-cut facility, located north of Hinton, became operational in late October 2013. The company has recently announced plans to construct Saturn II, which will be designed to extract about 2054 m^3/d of NGLs with an expected start-up date in late 2015.

Pembina's Resthaven project is designed to develop a combined shallow-cut and deep-cut facility at an existing gas processing plant. Pembina expects this facility to be in service in the third quarter of 2014. Once operational, the total plant capacity will be 2066 m^3/d, with the potential to process up to 2861 m^3/d of C_2+ mix.

Pembina has an existing C_2+ fractionator, RFS I, at Redwater. The company is also constructing a second fractionator, RFS II, which will double the company's C_2+ fractionation capacity to 23 065 m^3/d. RFS II is expected to come into service in the fourth quarter of 2015. The company also plans on upsizing certain facilities associated with RFS II to accommodate the possible future development of a third fractionator, RFS III, at Redwater. Pembina also has a C_3+ debottlenecking project to fully optimize the plant, which will increase throughput capacity by about 1430 m^3/d.

Keyera Corporation's (Keyera's) de-ethanization project is currently under construction to complete the addition of 4768 m^3/d of de-ethanization capacity to accept C_2+ mix NGLs at its Fort Saskatchewan fractionation plant. It is expected to be in service in the second half of 2014.

Keyera also announced the expansion of its NGL fractionation and storage facility in Fort Saskatchewan. The project will more than double the C_3+ fractionation capacity from about 4762 m^3/d to 10 317 m^3/d. The completion date of the project is the first quarter of 2016. Keyera will also be modifying its Simonette gas plant to enhance deep basin processing. The project will expand the plant's current capacity of 4.2 10^6 m^3/d of sour gas by an additional 2.8 10^6 m^3/d and improve condensate handling. The project's completion date is set for the second half of 2014.

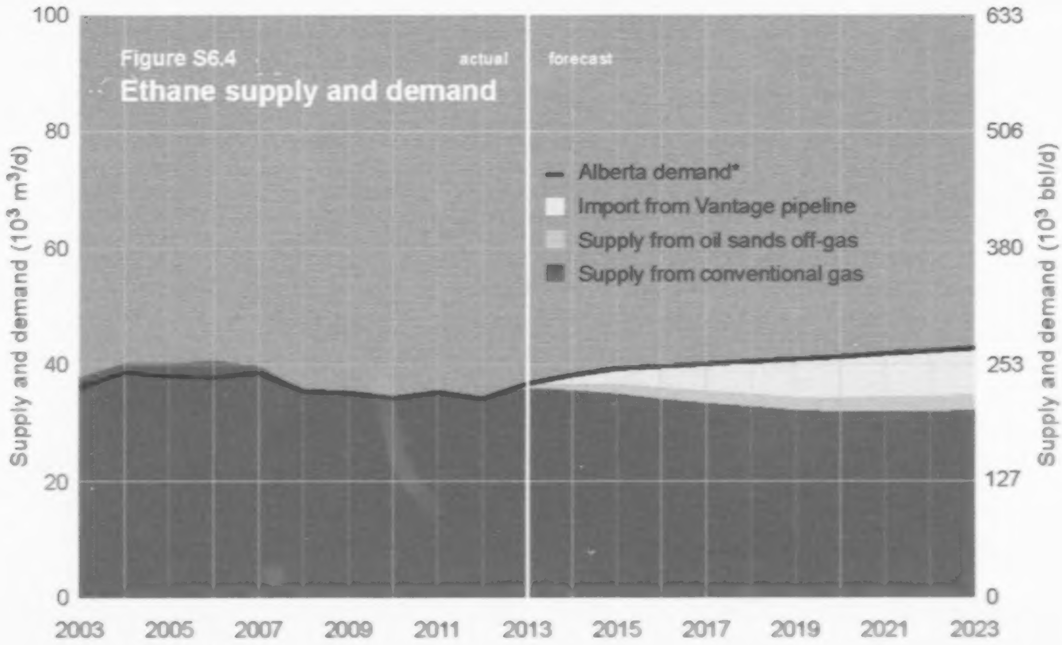
Keyera is ready to start construction on a new 11 10^6 m^3/d turbo expander at its Rimbey gas plant. The new turbo expander will allow producers to receive a higher netback for wet gas. Its original start-up date was late 2014 but has been delayed.

With several planned facility expansions, Pembina and Keyera are also undertaking several pipeline expansion projects, which are discussed in **Section 9.1.1.2**.

6.2.3 Ethane and Other Natural Gas Liquids Production – Forecast

The AER expects that the Alberta ethane supply will stay relatively high over the next two years despite total marketable natural gas production decreasing. As discussed, gas producers are focusing on the wetter gas stream with higher ethane content, and the midstream companies have announced a number of projects to maximize liquids recovery.

Figure S6.4 shows the AER's ethane supply and demand forecast. The AER expects ethane production from conventional gas to slightly decrease to 35.5 10^3 m^3/d in 2014. Ethane production from conventional gas will continue to decline until 2020, and then slightly recover for the rest of the forecast period as liquids-rich gas

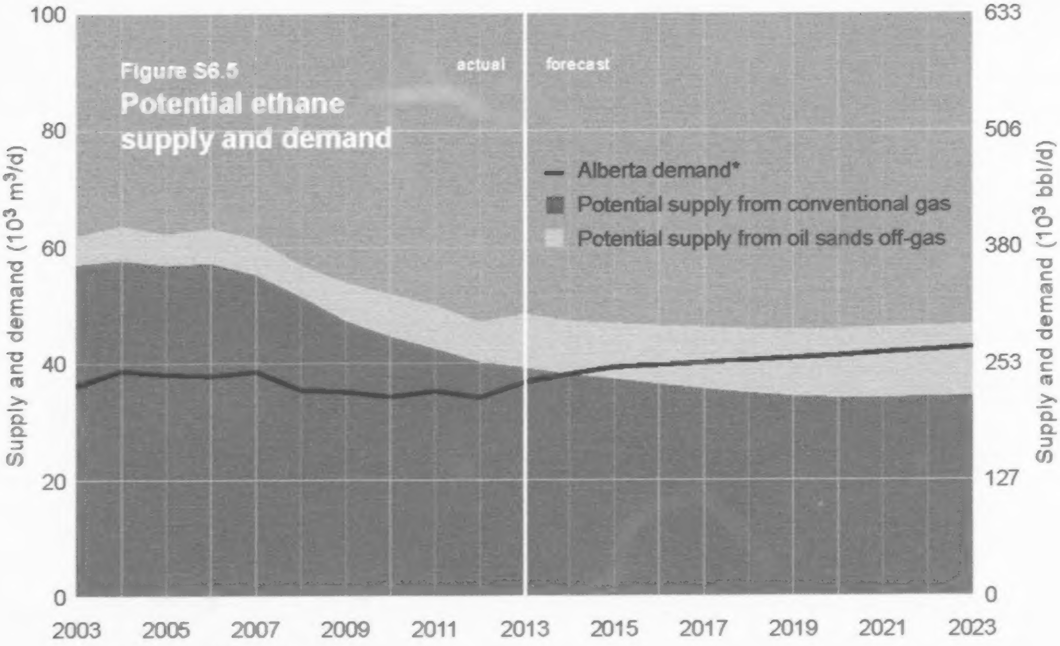


* Excludes solvent flood volumes.

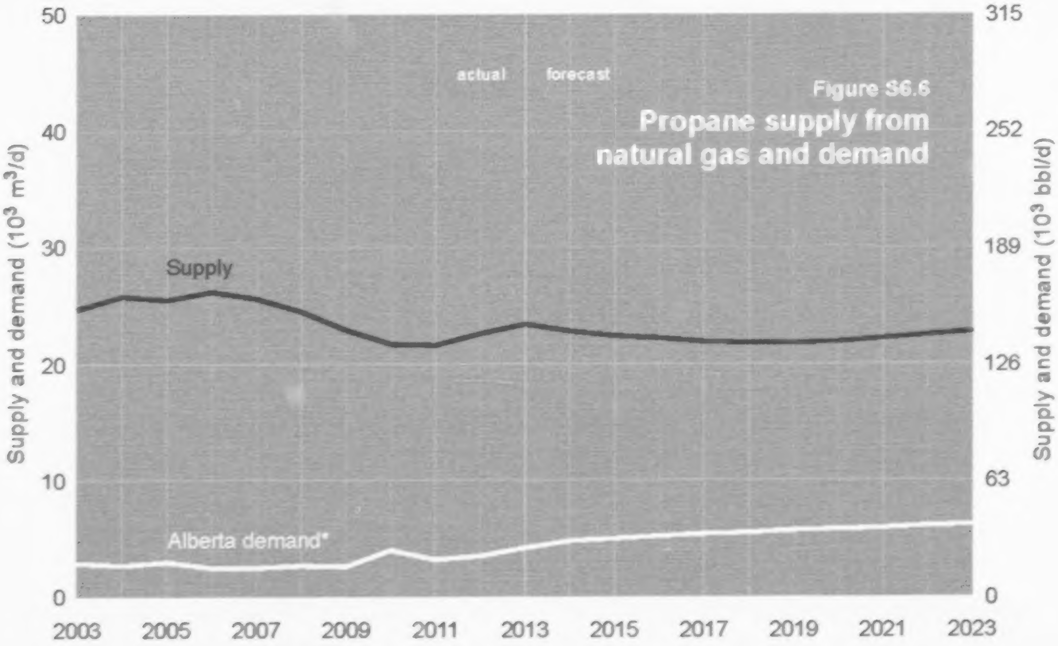
production from PSAC Areas 2 and 7 is also expected to start increasing in 2020. Small volumes of ethane were produced from off-gas in 2013, and the AER expects the ethane from off-gas to continue to grow gradually over the forecast period. Ethane demand and forecast to 2023 are discussed in **Section 6.2.4**.

Figure S6.5 shows the potential ethane supply from conventional natural gas and the potential ethane volumes that could be recovered from oil sands off-gas production. The ethane supply volumes from conventional natural gas are calculated based on the volume-weighted average ethane content of conventional gas in Alberta of 0.052 mol/mol and the assumption that 80 per cent of ethane could be recovered at processing facilities. Current processing plant capacity for ethane is about 70 10^3 m^3/d and is not a constraint to recovering the additional volumes forecast. Potential ethane supply from oil sands off-gas is calculated assuming an average ethane content of 16.2 per cent in the off-gas production volumes and an 80 per cent recovery rate of ethane. In 2023, 32.1 10^3 m^3/d of ethane is expected to be produced out of a total potential of 34.3 10^3 m^3/d of ethane from conventional gas, but only 2.7 10^3 m^3/d of ethane out of a total potential of 12.3 10^3 m^3/d of ethane from oil sands off-gas is projected to be extracted by 2023. As a result, imports of ethane from the United States started in the second quarter of 2014 to augment supply, and these imports will continue to increase throughout the forecast period, reaching 7.9 10^3 m^3/d in 2023.

Figures S6.6 to **S6.8** show the forecast for average daily production volumes and demand to 2023 for propane, butanes, and pentanes plus. The forecast for propane, butanes, and pentanes plus is higher when compared to last year's forecast as a result of a higher natural gas production forecast and increased liquid content in the gas stream. The propane, butanes, and pentanes plus demand forecasts are discussed in **Section 6.2.4**.



* Excludes solvent flood volumes.



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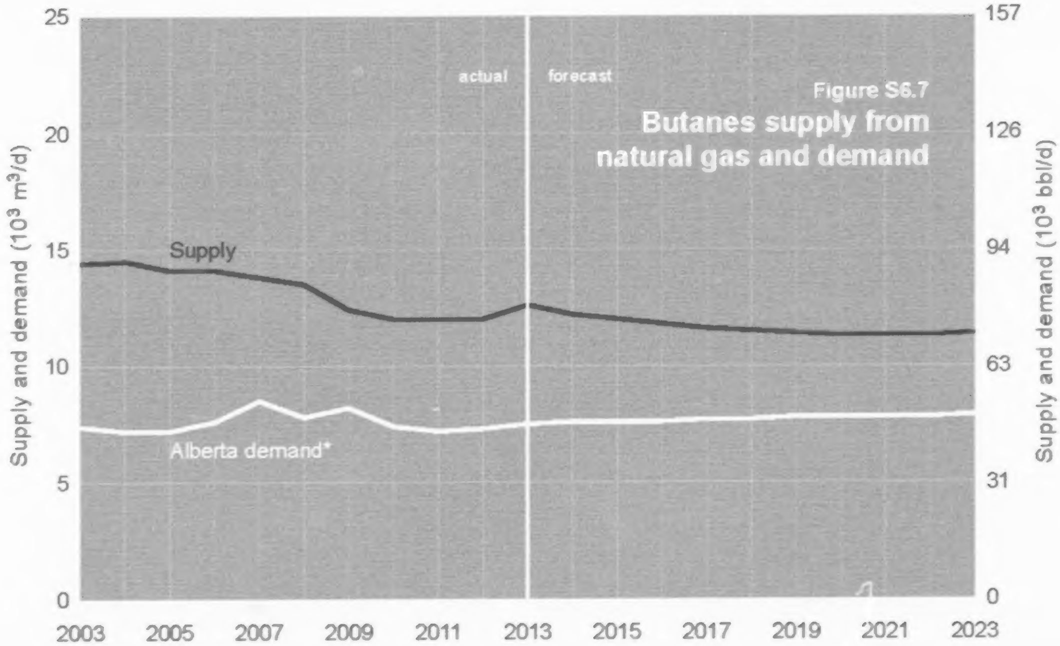
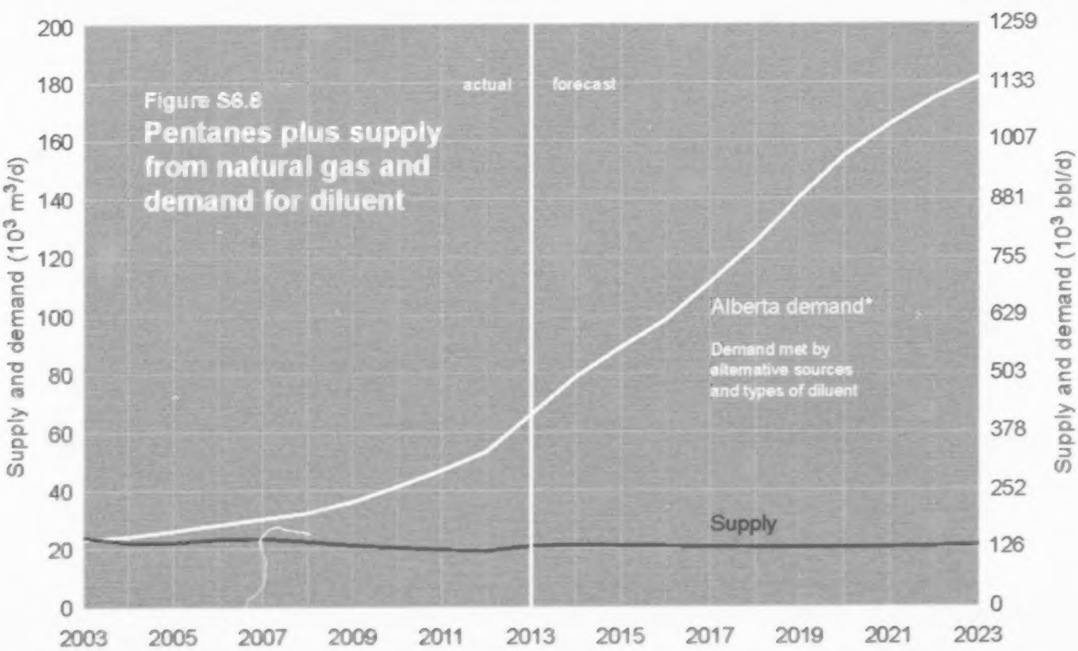


* Excludes solvent flood volumes.



* Excludes solvent flood volumes.

The AER expects propane production to decrease from 23.4 10^3 m^3/d in 2013 to 22.84 10^3 m^3/d in 2014 as natural gas production also decreases in the province. Propane production will continue to decline until 2020, and then begin to recover over the rest of the forecast period. Overall, the propane production forecast is higher than last year's forecast, reaching 22.8 10^3 m^3/d in 2023 compared with 20.7 10^3 m^3/d in 2022.

Butane production is forecast to decrease from 12.6 10^3 m^3/d in 2013 to 12.2 10^3 m^3/d in 2014. Production continues to decline until the end of the forecast period. The butane production forecast is higher than last year's, reaching 11.4 10^3 m^3/d in 2023 compared with 10.1 10^3 m^3/d in 2022.

Pentanes plus production in Alberta is expected to decline from 21.2 10^3 m^3/d in 2014 to 20.9 10^3 m^3/d in 2015. Production will remain relatively flat until 2020 and then slightly increase over the rest of the forecast period, reaching 21.0 10^3 m^3/d in 2023 as raw gas production from PSAC Areas 2 and 7 begin to increase.

6.2.4 Demand for Ethane and Other Natural Gas Liquids

The petrochemical industry in Alberta is the major consumer of ethane recovered from natural gas, with four ethylene plants using ethane as feedstock for the production of ethylene. The Joffre feedstock pipeline transports a range of feedstock from Fort Saskatchewan to Joffre. Currently, small volumes of propane supplement the ethane supplies used at the petrochemical plants at Joffre, where three of the four plants are located. The fourth is in Fort Saskatchewan. The plants in the province that use ethane as a feedstock operated collectively at 76 per cent of their capacity in 2013. The industry adds value to NGLs by upgrading them to be used in the manufacture of products such as plastic, rope, and building materials.

NOVA Chemicals has started construction on its polyethylene 1 (PE1) expansion project, which will produce between 0.43 million to 0.50 million tonnes per year of linear low-density polyethylene, increasing polyethylene production by 40 per cent. Ethylene is used as a feedstock.

The petrochemical industry in Alberta continues to benefit from the low gas price environment since the price of ethane, the primary feedstock for ethylene production, is linked to natural gas prices.

The AER expects that ethane demand by the ethylene producers in the province will increase over the next few years, judging by the continued investment in Alberta infrastructure such as extraction facilities and pipelines, as well as projects to expand polyethylene and ethylene glycol production. As shown in **Figure S6.4** and **Figure S6.5**, Alberta demand for ethane is projected to gradually increase from 36.7 10^3 m^3/d in 2013 to 42.7 10^3 m^3/d in 2023.

For the purpose of this forecast, it is assumed that the existing ethylene plants will increase their throughput capacity over the forecast period. As no ethylene plant projects in the province have been announced, it is assumed that no new ethylene plants requiring ethane as a feedstock will be built in Alberta over the forecast period. Since 2008, there have been no ethane removals from the province; this is expected to remain the case over the forecast period.

Demand for NGL mix streams in the form of C_2+ mix and C_3+ mix exists in Alberta as solvent for injection into enhanced oil recovery (EOR) schemes for conventional oil fields. Most of the NGL mix solvent is extracted at deep-cut facilities located adjacent to the injection facilities. Historically, small volumes of specification ethane were also delivered from Fort Saskatchewan to be used for injection at EOR schemes. In 2013, the ethane volumes in the solvent used for this purpose were equivalent to about 3 per cent of total ethane demand in Alberta. Propane and butanes injected as solvent were equivalent to 22.2 per cent and 10.1 per cent of the provincial total demand for the products, respectively. Small volumes of pentanes plus were injected as solvent in 2013. The AER expects that the demand for NGL mix volumes for injection will remain unchanged over the forecast period. The supply and demand figures in this section exclude solvent flood volumes for fields producing conventional oil.

Figure S6.6 shows Alberta's demand for propane compared with the total available supply from gas processing and straddle plants. The difference between Alberta requirements and total supply represents volumes used by ex-Alberta markets. Propane is used primarily as a fuel in remote areas for space and water heating, as an alternative fuel in motor vehicles, and for barbecues and grain drying. Alberta propane demand is forecast to increase from 4.2 10^3 m^3/d in 2013 to 4.76 10^3 m^3/d in 2014, then grow by an average of 3.0 per cent over the forecast period.

With the planned reversal and conversion of the Cochin pipeline and increased focus on liquids-rich natural gas drilling, Alberta will be oversupplied with propane. However, domestic propane demand from the petrochemical sector is expected to continue to grow moderately over the forecast period because propane is used as a feedstock for propylene and ethylene and demand has increased from the construction of Williams's PHD facility at Redwater. There are also other exports opportunities for Alberta propane supplies. Recently, Keyera announced plans to construct a rail terminal at Josephburg near Fort Saskatchewan, which will transport propane out of western Canada.

Figure S6.7 shows Alberta demand for butanes compared with the total available supply from gas processing plants. As with propane, the difference between Alberta butane requirements and total supply represents volumes used by markets outside of Alberta. Butanes are used as refinery feedstock, as well as in gasoline blends as an octane enhancer. The other petrochemical consumer of butanes in Alberta is a plant that uses butanes to produce vinyl acetate.

Butanes are also used as diluent (to reduce viscosity) and blended with heavy crude oil and bitumen to facilitate pipeline transportation of the product to market. Alberta demand, excluding solvent flood demand, was 7.5 10^3 m^3/d in 2013 compared with 7.3 10^3 m^3/d in 2012. Butane demand is expected to increase from 7.6 10^3 m^3/d in 2014 to 7.9 10^3 m^3/d in 2023. Alberta demand for butanes over the forecast period is expected to increase with forecast increases in nonupgraded bitumen. Another potential source for growth in demand for butanes is the increasing use with the solvent-aided process (SAP). SAP is a process whereby in situ bitumen producers inject butanes as a solvent to enhance, along with steam-assisted gravity drainage (SAGD), bitumen recovery.

The largest use of Alberta pentanes plus is as a diluent in the blending of heavy crude oil and bitumen. **Figure S6.8** shows the AER estimate of Alberta demand for pentanes plus used for diluent compared with the total available supply. Pentanes plus is also used as feedstock for the refinery in Lloydminster; this small volume (0.8 10^3 m^3/d in 2013) is not included in the figure. Pentanes plus demand is estimated based on assumed blending factors and heavy oil and bitumen production.

Demand for pentanes plus is expected to remain strong due to continued high diluent requirements. As a result, pentanes plus demand as a diluent is forecast to increase from 66.0 10^3 m^3/d in 2013 to 181.6 10^3 m^3/d in 2023 as the demand for diluent has increased with the increased forecast for bitumen production.

As illustrated in **Figure S6.8**, diluent demand is estimated to have exceeded Alberta supply around 2004. The current estimated demand reflects the inadequate Alberta supply of pentanes plus since 2004, which has resulted in the assessment and use of alternative sources (imports) and types of diluent. Alberta currently imports offshore condensate by rail from Kitimat, British Columbia.

Alberta imports of pentanes plus are expected to increase over the next 10 years with growing oil sands demand. Currently, Alberta imports pentanes plus on trucks and rail cars and in pipelines, including in Enbridge Inc.'s Southern Light pipeline, which transports diluent from Chicago to Edmonton and has a capacity to deliver 28.6 10^3 m^3/d.

Section 9.1.1.3 describes the main NGL pipelines systems in Alberta, including new pipeline project announcements, and the current and future sources of diluent that will be needed to facilitate transportation of nonupgraded bitumen to markets.

7 SULPHUR

Sulphur is a chemical element found in conventional natural gas, crude bitumen, and crude oil. It is extracted and sold primarily for use in making fertilizer. Currently, most produced sulphur is derived from the hydrogen sulphide (H_2S) contained in about 20 per cent of the remaining established reserves of conventional natural gas.

HIGHLIGHTS

Remaining established sulphur reserves decreased 3 per cent, mainly due to production.

Sulphur production from gas processing declined 1 per cent from 2012 to 2013, while sulphur production from crude bitumen increased by 6 per cent.

Total sulphur production increased from 4.4 million tonnes in 2012 to 4.5 million tonnes in 2013.

7.1 Reserves of Sulphur

7.1.1 Provincial Summary

The AER estimates the remaining established reserves of elemental sulphur in the province as of December 31, 2013, to be 117.4 million tonnes (10^6 t), down 3 per cent from 2012. This decrease is mainly due to production. **Table R7.1** shows the changes in sulphur reserves over the past year. The AER does not estimate sulphur reserves from sour crude oil since only a very small portion of Alberta's sour crude oil is refined in the province.

7.1.2 Sulphur from Natural Gas

The AER estimates that 19.4 10^6 t of remaining established sulphur from natural gas reserves were in sour gas pools at year-end 2013, a decrease of 6.7 per cent from 2012. Remaining established sulphur reserves have been calculated using a provincial recovery factor of 97 per cent, which takes into account plant efficiency, acid-gas flaring at plants, acid-gas injection, and solution-gas flaring.

The AER's sulphur reserve estimates from natural gas are shown in **Table R7.2**. Fields containing the largest recoverable sulphur reserves are listed individually. Fields with significant volumes of sulphur reserves in 2013 are Waterton, Crossfield East, and Okotoks. Combined, these reserves account for 4.7 10^6 t, or 24 per cent, of the remaining established reserves of sulphur from natural gas.

The AER estimates the ultimate potential for sulphur from natural gas to be 394.8 10^6 t, which includes 40 10^6 t from pools with ultrahigh concentrations of H_2S currently not on production. Based on initial established reserves of 273.8 10^6 t, this leaves 121.0 10^6 t of yet-to-be-established reserves from future discoveries of conventional gas.

7.1.3 Sulphur from Crude Bitumen

Crude bitumen in oil sands deposits contains significant amounts of sulphur. As a result of current bitumen upgrading operations, an average of 90 per cent of the

Table R7.1 Reserve and production change highlights (10^6 t)

	2013	2012	Change[a]
Initial established reserves from			
Natural gas	273.8	272.8	+1.0
Crude bitumen[b]	128.4	128.4	0
Total	**402.2**	**401.2**	**+1.0**
Cumulative production from			
Natural gas	254.4	252.0	+2.4
Crude bitumen	30.4	28.3	+2.1
Total	**284.8**	**280.3**	**+4.5**
Remaining established reserves from			
Natural gas	19.4	20.8	-1.4
Crude bitumen[b]	98.0	100.1	-2.1
Total	**117.4**	**120.9**	**-3.5**
Annual production	4.5	4.4	+0.1

[a] Any discrepancies are due to rounding.

[b] Reserves of elemental sulphur from bitumen mines under active development as of December 31, 2013. Reserves from the entire surface mineable area are larger.

sulphur contained in the crude bitumen is either recovered in the form of elemental sulphur or remains in the by-products from upgrading bitumen, such as coke.

It is currently estimated that 211.8 10^6 t of sulphur could be recovered from the 5.23 billion cubic metres (10^9 m^3) of remaining established crude bitumen reserves in the entire surface mineable area. These sulphur reserves were estimated by using a factor of 40.5 t of sulphur per thousand cubic metres of crude bitumen. This ratio reflects both current operations and the expected use of high-conversion hydrogen-addition upgrading technology for the future development of surface-mineable crude bitumen reserves. Hydrogen-addition technology recovers more sulphur than alternative carbon-rejection technology. With the latter technology, more of the sulphur in the bitumen remains in upgrading residues and less is converted to H_2S.

If less of the mineable crude bitumen reserves are upgraded with the hydrogen-addition technology than is currently estimated or if less of the mineable reserves are upgraded in Alberta, the total sulphur reserves will be less.

In 2013, the Nexen Long Lake upgrader continued to upgrade in situ bitumen, resulting in the production of small quantities of sulphur, most of which was not marketed. The AER will include in situ upgrading projects in future reports as they come on stream.

7.1.4 Sulphur from Crude Bitumen Reserves under Active Development

Only some of the crude bitumen produced from mining will be processed by the existing Suncor, Syncrude, Shell Muskeg River, Shell Jackpine, and CNRL Horizon upgraders. Consequently, the AER's estimate of

Table R7.2 Remaining established reserves of sulphur from natural gas as of December 31, 2013[a]

Field	Remaining reserves of marketable gas (10^6 m^3)	H_2S content (%)[b]	Remaining established reserves of sulphur Gas (10^6 m^3)	Solid (10^3 t)
Bighorn	2 344	6.8	191	260
Brazeau River	8 340	3.4	341	463
Burnt Timber	940	17.7	242	329
Caroline	5 498	9.5	672	911
Coleman	747	26.6	296	402
Crossfield	2 470	17.4	658	893
Crossfield East	1 937	27.8	928	1 259
Elmworth	21 130	1.0	234	318
Hanlan	6 075	8.9	716	970
Jumping Pound West	3 229	6.7	269	365
La Glace	2 190	6.6	168	228
Limestone	3 158	12.6	537	728
Lone Pine Creek	1 970	6.9	166	225
Marsh	892	16.2	196	266
Moose	2 794	12.8	468	634
Okotoks	1 527	32.0	898	1 217
Panther River	2 547	5.7	182	246
Pembina	24 155	0.7	235	319
Pine Creek	7 026	4.0	329	446
Rainbow	9 040	2.0	246	333
Rainbow South	2 608	6.6	253	343
Ricinus	3 844	3.7	164	223
Ricinus West	887	32.2	497	674
Simonette	2 880	8.2	331	448
Waterton	4 536	22.3	1 641	2 225
Wildcat Hills	6 287	4.4	323	438
Wimborne	1 529	9.4	173	234
Windfall	1 594	13.3	303	410
Subtotal	**132 174**	**6.8**	**11 656**	**15 806**
All other fields	765 363	0.3	2 619	3 568
Total	**897 537**	**1.4**	**14 274**	**19 374**

[a] Any discrepancies are due to rounding.

[b] Volume-weighted average based on remaining raw producible gas.

the initial established sulphur reserves in 2013 from these active projects is 128.4 10^6 t, representing 61 per cent of the potentially recoverable sulphur from the remaining established crude bitumen reserves for the entire surface mineable area. A total of 30.4 10^6 t of sulphur has been produced from these projects, leaving 98.0 10^6 t of remaining established reserves. This is a decrease of 2 per cent from the remaining reserves in 2012. This decrease in remaining reserves is due to the production of 2.1 10^6 t of sulphur in 2013.

7.2 Supply of and Demand for Sulphur

7.2.1 Sulphur Production – 2013

There are three sources of sulphur production in Alberta: sour natural gas processing, crude bitumen upgrading, and crude oil refining into petroleum products. In 2013, Alberta produced 4.46 10^6 t of sulphur, of which 2.38 10^6 t were derived from sour gas, 2.07 10^6 t from bitumen upgrading, and just 12 thousand (10^3) t from oil refining. The total sulphur production in 2013 reversed the downward trend that has been observed since 2000 and represented an increase of 2 per cent from the 2012 levels. Most of Canada's sulphur is produced in Alberta.

7.2.1.1 Sulphur Production from Natural Gas

Figure S7.1 shows historical sulphur production from gas processing plants. Sulphur production volumes are a function of raw gas production, sulphur content, and gas plant recovery efficiencies. This trend is evident in the decline in sulphur production from gas processing plants since 2000. The decline is a result of the lower natural gas production and lower sulphur content in the gas stream.

Table S7.1 shows the changes in sulphur production from major gas processing plants over the past year. The Shell Caroline and Shell Waterton gas plants had major turnarounds in 2012, which resulted in significantly lower gas production compared to 2013 levels.

Sulphur stockpiles stored as solid blocks at gas processing plants have been drawn down significantly in recent years as the result of an increase in global sulphur demand. Figure 15 in the Overview section illustrates historical

Table S7.1 Sulphur production from gas processing plants (10^3 t)

Major plants	2013	2012	Change	Per cent change
Shell Caroline	596	498	98	20
Shell Waterton	437	280	157	56
Husky Strachan	196	257	-61	-24
Shell Jumping Pound	168	186	-18	-10
Semcams Kaybob South	126	127	-1	-1
Keyera Strachan	96	131	-35	-27
Suncor Hanlan	107	131	-24	-18
Shell Burnt Timber	108	118	-10	-8.5
Total	**1728**	**1834**	**-106**	**-6**

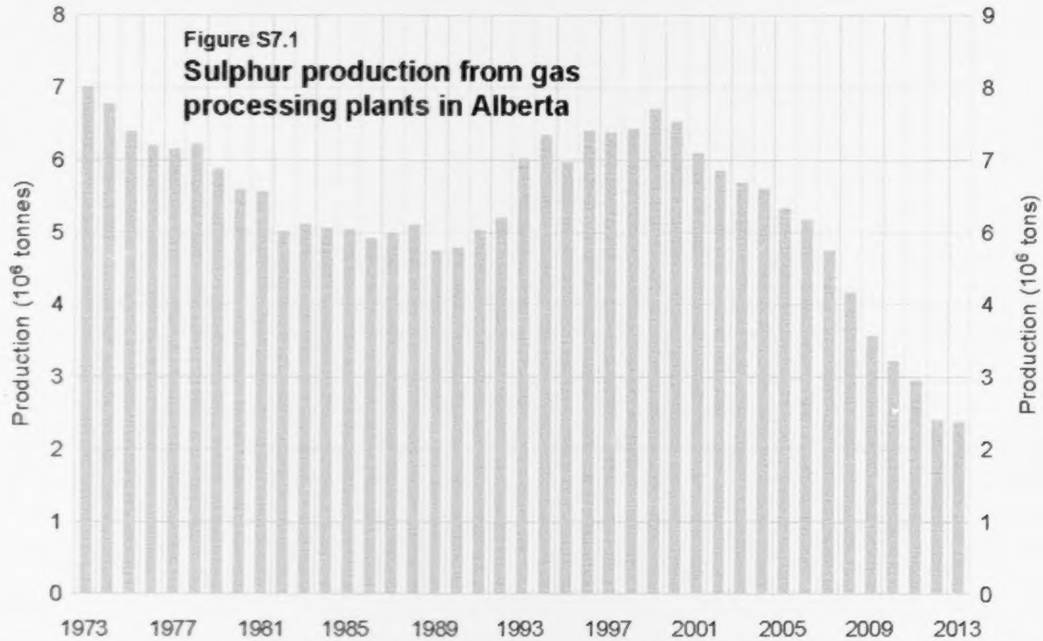


Figure S7.1
Sulphur production from gas processing plants in Alberta

sulphur closing inventories at gas processing plants and oil sands operations, as well as sulphur prices. Inventory blocks of sulphur at gas processing plants in Alberta were 1.22 10^6 t at year-end 2013, down from 1.46 10^6 t at year-end 2012 and 1.88 10^6 t in 2011.

7.2.1.2 Sulphur Production from Crude Bitumen Upgrading

Historical sulphur production from the five oil sands upgrader operations is shown in **Figure S7.2**. Total production in 2013 was 2.08 10^6 t, up 6 per cent from 2012 production of 1.96 10^6 t. With the exception of Syncrude, all of the crude bitumen upgraders experienced increases in sulphur production.

7.2.2 Sulphur Production – Forecast

Total Alberta sulphur production from sour gas, crude oil, and bitumen upgrading and refining is depicted in **Figure S7.3**. Sulphur production from sour gas is expected to decrease from 2.38 10^6 t in 2013 to 2.08 10^6 t—about 14 per cent—by the end of the forecast period; however, sulphur recovery from bitumen upgrading and refining is expected to increase from 2.08 10^6 t in 2013 to 2.83 10^6 t (about 36 per cent). The large increase in sulphur from bitumen upgrading is due to the increasing production of upgraded bitumen. The sulphur production forecast takes into account the return of Suncor and CNRL to upgraded bitumen production targets following disruptions at their respective facilities in early 2012.

Sulphur recovery from Alberta refineries declined to 12 10^3 t in 2013 from 19 10^3 t in 2012. With the anticipation that Alberta refineries' throughput will increase over time, the forecast sulphur recovery is expected to reach 17 10^3 t in 2014, remain at the same level until 2021, and increase to 18 10^3 t in 2022 and 2023.

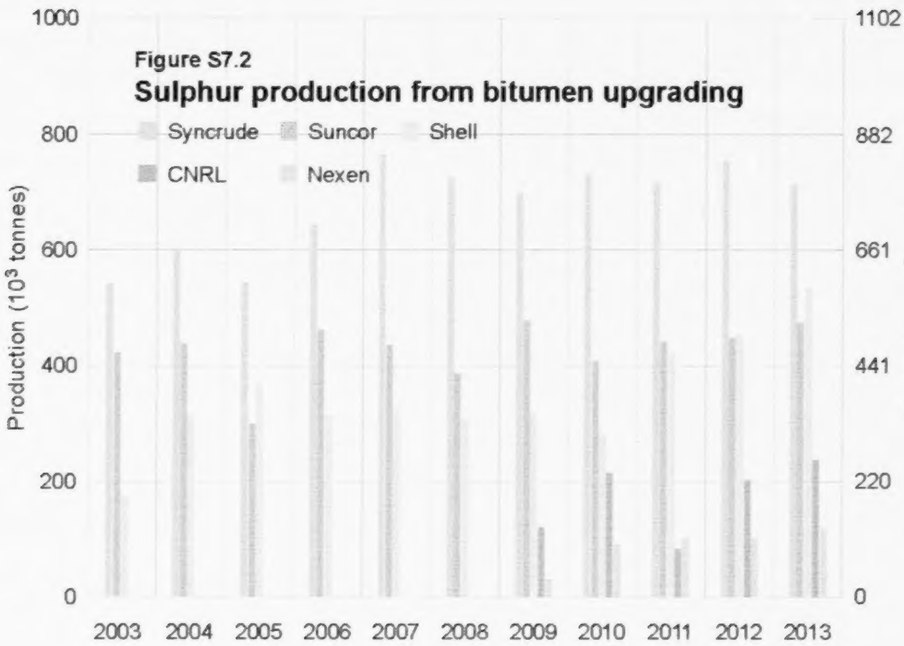


Figure S7.2
Sulphur production from bitumen upgrading
Syncrude
Suncor
Shell
CNRL
Nexen
Production (10^3 tonnes)
Production (10^3 tons)
1000
800
600
400
200
0
1102
882
661
441
220
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013

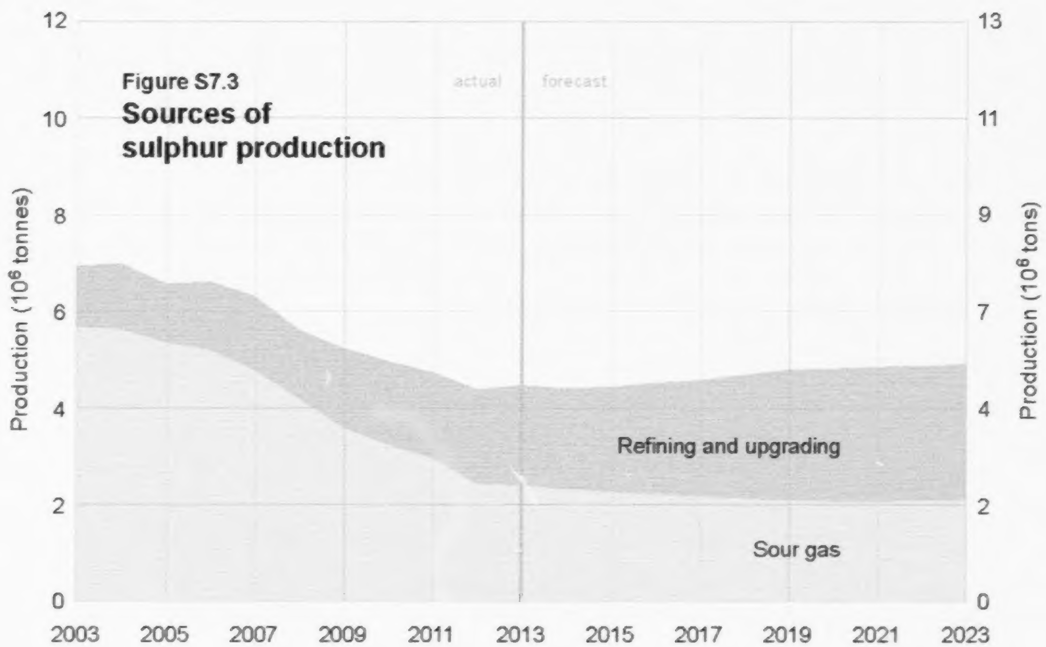


Figure S7.3
Sources of sulphur production
actual
forecast
Refining and upgrading
Sour gas
Production (10^6 tonnes)
Production (10^6 tons)
12
10
8
6
4
2
0
13
11
9
7
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023

7.2.3 Sulphur Demand

Disposition of sulphur within Alberta averaged 460 10^3 t per year between 2008 and 2010. More recent data on the disposition of sulphur in the province may include Alberta plant-to-plant transfers, which have likely caused the disposition volume to appear higher than actual. The AER considers the 2008–2010 average to be representative of 2011 to 2013 disposition and has also used that figure in the forecast period to 2023.

Sulphur is used in the production of phosphate fertilizer and kraft pulp and in other chemical operations. Alberta produces more sulphur than any other province in Canada, and the majority of Alberta production is shipped outside the province. Canadian exports in 2013 were 3.3 10^6 t, an 11 per cent decrease from 3.7 10^6 t in 2012. **Figure S7.4** shows the historical Canadian export volumes.

In 2013, Free On Board (FOB) Vancouver sulphur prices averaged US$104, declining 48 per cent from the previous year's average price of US$201.[1]

China is the world's largest importer of sulphur, which it uses primarily to make sulphuric acid to produce phosphate fertilizer. Exports to China have significantly decreased from 1094 10^3 t in 2012 to 717 10^3 t in 2013 as a result of increased availability from closer producing countries such as Saudi Arabia, Kazakhstan, Japan, South Korea, and Iran. Nearly half of Canadian exports are sent to the United States: 1577 10^3 t in 2013, slightly higher than 1569 10^3 t in 2012.

Because sulphur is fairly easy to store, differences between production and disposition have traditionally been accommodated through net additions to or removals from sulphur stockpiles. If demand exceeds supply, sulphur is withdrawn from stockpiles; if supply exceeds demand, sulphur is added to stockpiles. **Figure S7.5** shows the historical and forecast total sulphur supply and demand, including inventory additions and withdrawals.

In the early part of the previous decade, weak global sulphur demand resulted in less demand for Alberta exports and, as a result, Alberta built up a significant stockpile of sulphur. Since 2004, supply and demand have generally been in balance, with small withdrawals from inventory stockpiles. The forecast assumes that, on average, this situation will continue as declining production from natural gas processing plants is replaced by increasing sulphur recovery from bitumen upgrading. The forecast also assumes that demand will remain approximately constant in the first half of the forecast period and rise slightly in the second half.

[1] FOB Vancouver represents an international pricing point where, after a commodity is loaded on a ship, the liability for and the cost of shipping the commodity transfers from a seller to a buyer.

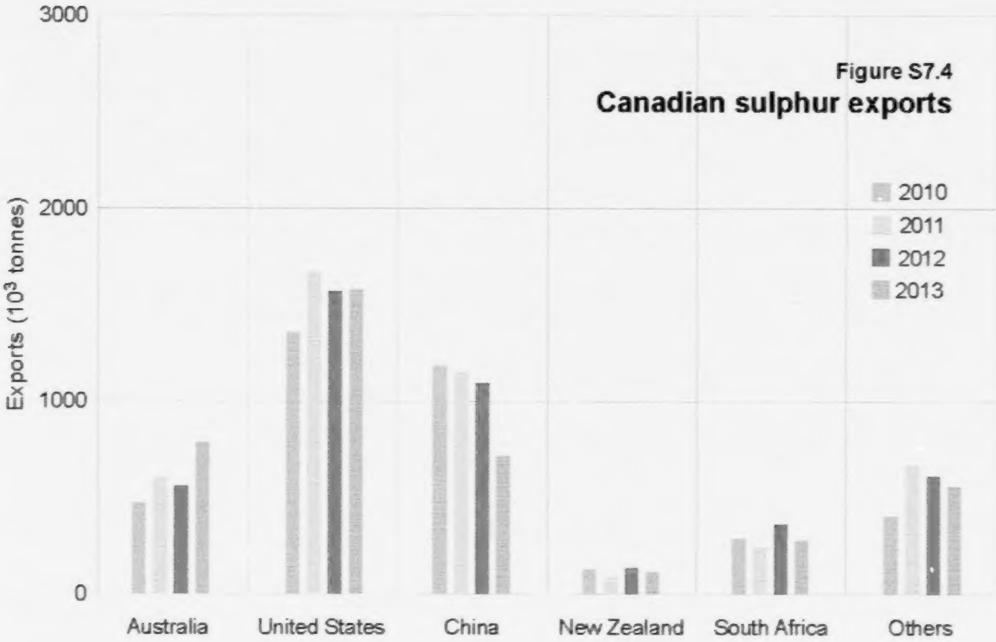


Figure S7.4
Canadian sulphur exports
Exports (10^3 tonnes)
3000
2000
1000
0
2010
2011
2012
2013
Australia
United States
China
New Zealand
South Africa
Others

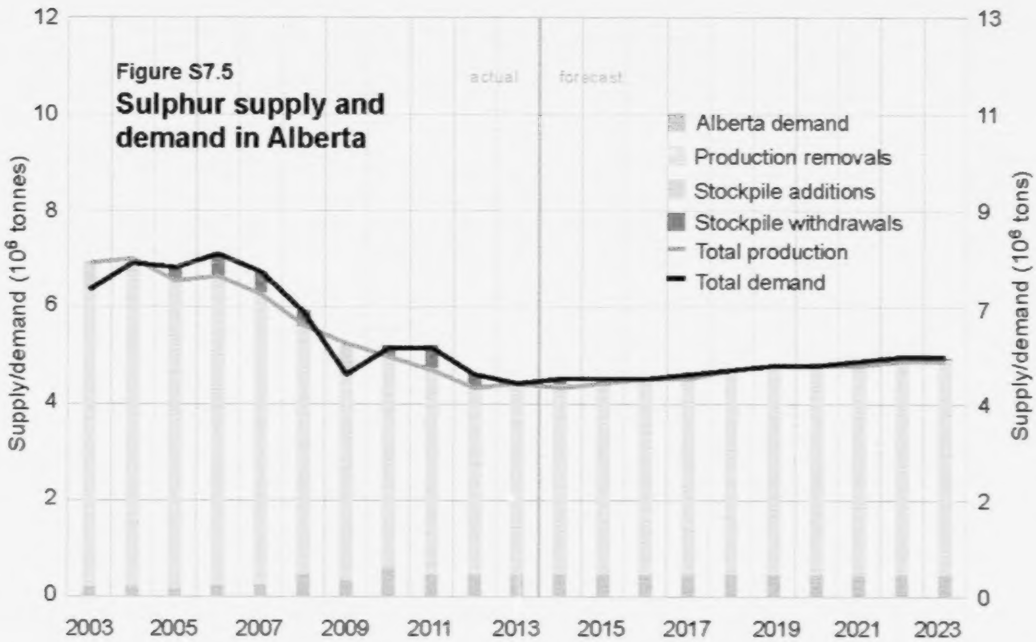


Figure S7.5
Sulphur supply and demand in Alberta
Supply/demand (10^6 tonnes)
Supply/demand (10^6 tons)
actual
forecast
Alberta demand
Production removals
Stockpile additions
Stockpile withdrawals
Total production
Total demand
12
10
8
6
4
2
0
13
11
9
7
4
2
0
2003
2005
2007
2009
2011
2013
2015
2017
2019
2021
2023

HIGHLIGHTS

Remaining established reserves under active development decreased slightly in 2013 due to production but still represent decades of supply.

Overall coal production was 3 per cent higher in 2013. Metallurgical bituminous coal production decreased 3 per cent, thermal bituminous coal production decreased 10 per cent, and subbituminous coal increased 5 per cent.

8 COAL

Coal is a combustible sedimentary rock with greater than 50 per cent organic matter. Coal occurs in many formations across central and southern Alberta, with lower-energy-content coals in the plains region, shifting to higher-energy-content coals in the foothills and mountain regions.

Production of coal from mines is called raw coal. Some coal, particularly that from the mountain and foothills regions of Alberta, needs to be processed prior to marketing; this processed coal is referred to as clean coal. Clean coal (normally sold internationally) and raw coal from the plains region (normally sold within Alberta) are termed "marketable coal." In this report, "reserves" refers to raw coal unless otherwise noted.

The possible commercial production of synthetic gas from coal (synthetic coal gas) in Alberta is still being investigated, and legislation is in place for regulating in situ coal gasification (ISCG) development. A discussion of ISCG is found in **Section 8.1.2.3**.

The following coal reserves and production information summarizes and nominally updates the material found in the AER serial publication *ST31: Reserves of Coal, Province of Alberta* (2000 edition). See *ST31* for more detailed information and a greater understanding of the parameters and procedures used to calculate established coal reserves.

8.1 Reserves of Coal

8.1.1 Provincial Summary

The AER estimates the remaining established reserves of all types of coal in Alberta as of December 31, 2013, to be 33.2 gigatonnes[1] (Gt) (36.6 billion tons). Of this amount, 22.6 Gt (or about 69 per cent) is considered recoverable by underground mining methods and 10.4 Gt is recoverable by surface mining methods. Of the total remaining established reserves, less than 1 per cent is within permit boundaries of mines active in 2013. **Table R8.1** gives a summary by rank of resources and reserves from 244 coal deposits.

Minor changes in remaining established reserves from December 31, 2012, to December 31, 2013, resulted from additions to cumulative production. During 2013,

[1] Giga = 10^9.

Table R8.1 Established initial in-place resources and remaining reserves of raw coal in Alberta as of December 31, 2013 (Gt)[a]

Rank Classification	Initial in-place resources	Initial reserves	Cumulative production	Remaining reserves
Low- and medium-volatile bituminous[b]				
Surface	1.74	0.811	0.254	0.557
Underground	5.06	0.738	0.112	0.626
Subtotal	**6.83**[c]	**1.56**[c]	**0.366**	**1.19**[c]
High-volatile bituminous				
Surface	2.56	1.89	0.210	1.68
Underground	3.30	0.962	0.0470	0.915
Subtotal	**5.90**[c]	**2.88**[c]	**0.257**	**2.62**[c]
Subbituminous[d]				
Surface	13.6	8.99	0.871	8.12
Underground	67.0	21.2	0.0680	21.1
Subtotal	**80.7**[c]	**30.3**[c]	**0.939**	**29.4**
Total	**93.7**[c]	**34.8**[c]	**1.56**[e]	**33.2**

[a] Tonnages have been rounded to three significant figures.

[b] Includes minor amounts of semi-anthracite.

[c] Totals for resources and reserves are not arithmetic sums but are the result of separate determinations.

[d] Includes minor amounts of lignite.

[e] Any discrepancies are due to rounding.

the low- and medium-volatile bituminous, high-volatile bituminous, and subbituminous production tonnages were 0.005 Gt, 0.007 Gt, and 0.023 Gt, respectively.

8.1.2 In-Place Resources

There was no change to the in-place resource estimate over the previous year.

The AER estimates the initial in-place resource of coal to be 94 Gt, of which the largest component, 81 Gt, is the subbituminous coal of the plains region. Most of this subbituminous coal exists at depths greater than 60 metres (m) but less than 600 m.[2] There is significant additional resource potential for coal within Alberta, as discussed in **Section 8.1.4**.

8.1.2.1 Geology and Coal Occurrence

Coal occurs extensively in Alberta through the nonmarine units of the sequence of Jurassic- to Paleocene-aged formations. The coal-bearing formations underlie about 300 000 square kilometres—almost half of Alberta. **Figure R8.1** shows the subcrops of most of the coal-bearing formations, and their equivalents, in Alberta.

[2] Coal is known to exist below a depth of 600 m; however, it is beyond what is considered potentially mineable.

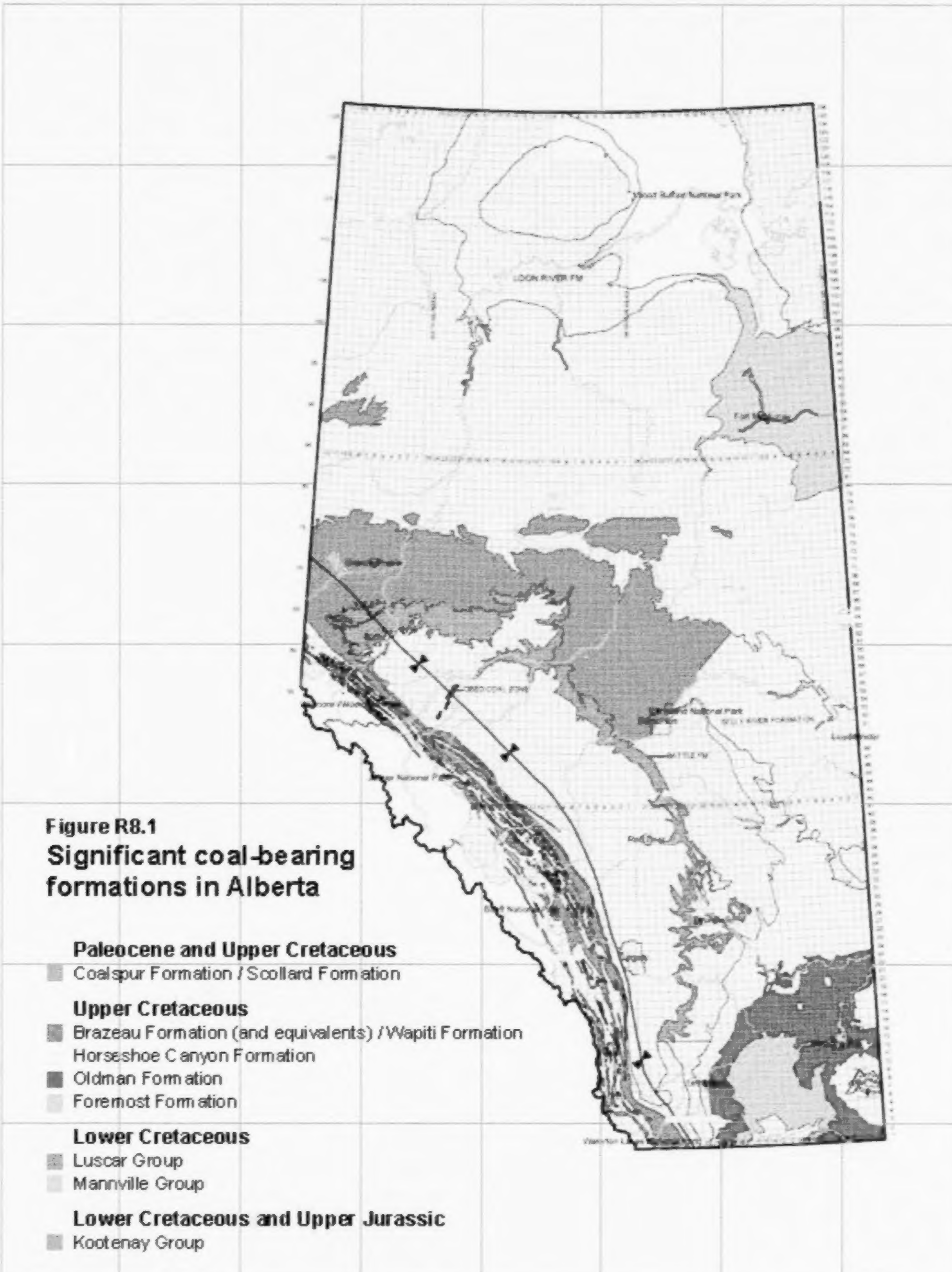


Figure R8.1
Significant coal-bearing formations in Alberta

Coal, with or without thin clastic layers called partings, occurs in layered accumulations called seams. Coal maturity, or rank, is measured on the basis of calorific value for lower ranked coals and carbon content for higher ranked coals. Coals of all rank groups, from lignite to semi-anthracite, occur in Alberta.

The AER has subdivided Alberta's coal-bearing regions into three designated regions (broadly shown in **Figure S8.1** in **Section 8.2.1**) based on rank, geology, and topography, so as to group coals by method of recovery and market. The mountain region exhibits complex geological structures and steep topography with higher ranked coal amenable to export for metallurgical purposes. The foothills region exhibits moderately complex structures and hilly topography with moderate-ranked coals amenable to export for thermal purposes. The plains region is the largest and exhibits generally flat-lying seams and flat or incised plateau topography with lower ranked coals amenable for domestic thermal purposes. The plains region contains about 88 per cent of Alberta's coal, most of which is subbituminous.

Figure R8.2 shows periods of exploration for coal in Alberta. Recent coal exploration has been predominately within areas where mine permits have been issued by the AER. While very significant coal resources were identified from holes drilled in the 1970s and 1980s, very few areas, other than currently producing areas, have seen follow-up drilling due to lack of markets.

8.1.2.2 Coal Mineability

In general, shallow coal is mined more economically by surface than by underground methods and is classified as surface mineable. At some stage of increasing depth and strip ratio,[3] the economic advantage passes to underground mining; this coal is considered underground mineable. The classification scheme used to differentiate between surface- and underground-mineable coal is very broadly based on depth and strip ratio and is designed to reflect relative costs, but it does not necessarily mean that the coal could be mined under the economic conditions prevailing today.

These classifications are used to categorize total coal in-place. Further analysis is done to determine which portions of this coal may be developed and which portions may be recovered. Some in-place coal, such as underground thin seams, is unlikely to be developed by mining methods but is included in the total because of past production. Additionally, some of the coal currently classified as underground may become the target of commercial ISCG development. If this becomes the case, the AER will split the underground classification into mineable and in situ components.

8.1.2.3 In Situ Coal Gasification

There are two main types of coal gasification processes: ISCG and surface-facility gasification from mined coal. Surface-facility gasification processes conventionally mined coal, and those mineable coal reserves would be included in **Table R8.1**. Currently, however, there are no surface-gasification facilities in Alberta.

[3] The strip ratio is the amount of overburden that must be removed to gain access to a unit amount of coal.

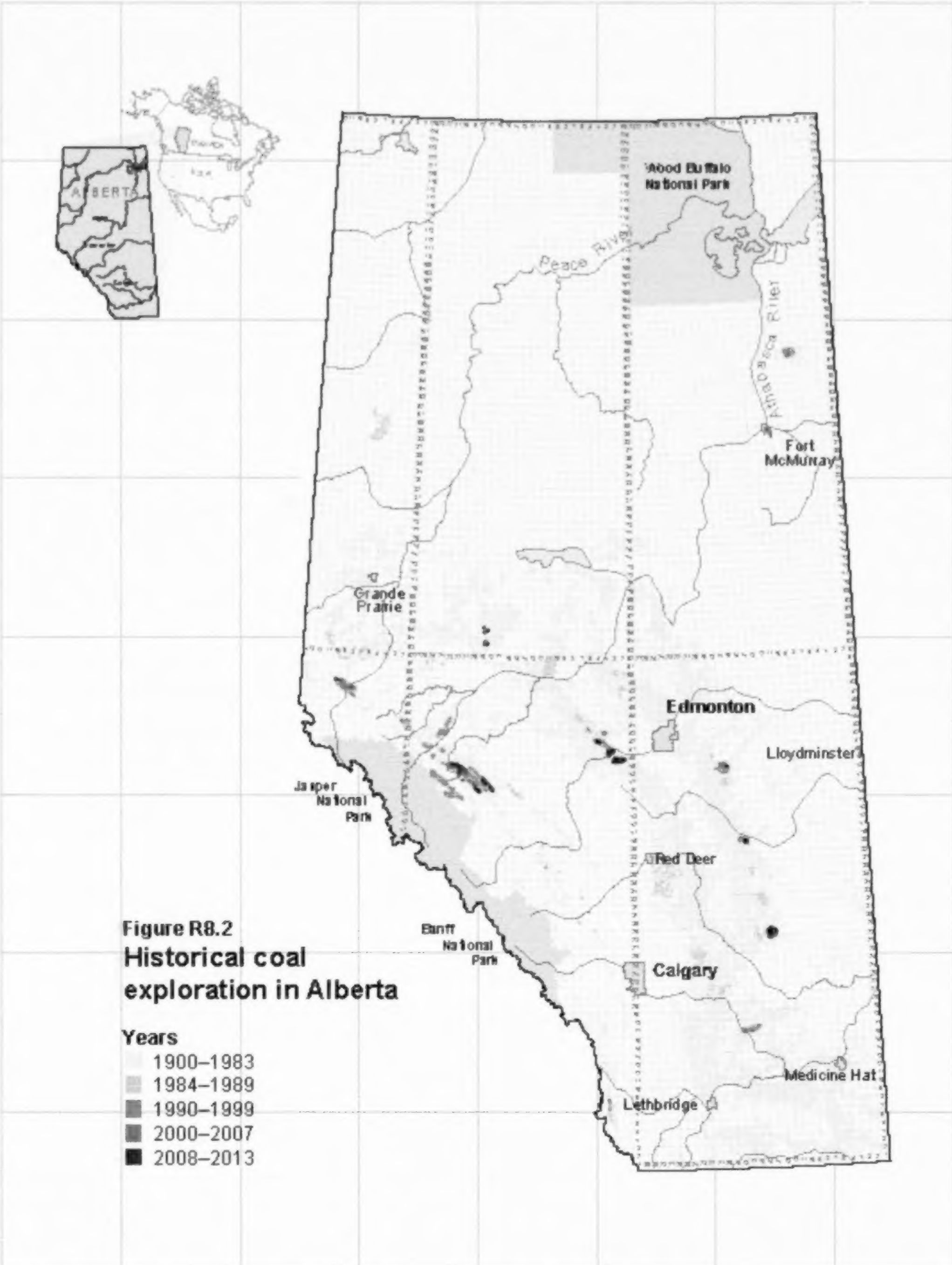


Figure R8.2
Historical coal exploration in Alberta

Years
- 1900–1983
- 1984–1989
- 1990–1999
- 2000–2007
- 2008–2013

ISCG uses wellbores to access coal seams at depth. ISCG thermally reduces coal to simpler hydrocarbons that can be produced up a wellbore. Any ISCG-derived gas would, by its nature, incorporate any coalbed methane gas (see **Section 5**) contained within the targeted coals. Currently, ISCG synthetic coal gas is limited to a small quantity. Therefore, neither synthetic coal gas volumes nor their associated coal resource tonnages have been included in this report. However, Alberta's vast quantities of coal could supply a large resource base should development prove commercial.

Two ISCG pilot projects have been approved but neither was operational in 2013. Future ISCG development may take place at depths below those currently assumed to be mineable.

8.1.3 Established Reserves

Several techniques, geostatistical methods in particular, have been used to calculate in-place volumes, with separate volumes calculated for surface- and underground-mineable coal. Certain parts of deposits are considered nonrecoverable for technical, environmental, economic, or safety reasons and, therefore, have no recoverable reserves. For the remaining areas, recovery factors have been determined for the surface-mineable coal and the thicker underground classes of coal seams.

A recovery factor of 90 per cent has been assigned to the remaining in-place surface-mineable area, followed by an additional small coal loss at the top and a small dilution at the bottom of each seam.

In the case of underground-mineable coal, geologically complex environments may make mining significant parts of some deposits uneconomic. Because there is seldom sufficient information to outline such areas, it is assumed that, in addition to the coal previously excluded, only a portion of the remaining deposit areas would be mined. Thus a "deposit factor" has been determined whereby, on average, only 50 per cent of the remaining deposit area is considered mineable in the mountain region, 70 per cent mineable in the foothills, and 90 per cent mineable in the plains—the three regions in Alberta designated by the AER where coals of similar quality and mineability are recovered.

A mining recovery factor of 75 per cent is then applied to both medium (1.5 to 3.6 m) and thick (>3.6 m) seams, with a maximum recoverable thickness of 3.6 m applied to thick seams. Thin seams (0.6 to <1.5 m) are not currently considered recoverable by underground methods.

Table R8.2 shows the established resources and reserves within the current permit boundaries of those mines active (either producing or under construction) in 2013. In 2013, the Obed mine operation was suspended. In February 2014, Coalspur Mines (Operating) Limited received approval from the AER for its Vista Coal Project near Hinton. This mine project will be included in **Table R8.2** once production or significant construction starts.

8.1.4 Ultimate Potential

A large degree of uncertainty is associated with estimating an ultimate potential and new data could substantially alter results. Two methods have been used to estimate the ultimate potential of coal: volumetric and trend analysis. The volumetric method gives a broad estimate of area, coal thickness, and recovery ratio for each coal-bearing horizon, while the trend analysis method estimates the ultimate potential from the trend of initial reserves versus exploration effort.

Table R8.2 Established resources and reserves of raw coal under active development as of December 31, 2013

Rank Mine	Permit area (ha)[a]	Initial in-place resources (Mt)[b]	Initial reserves (Mt)	Cumulative production (Mt)	Remaining reserves (Mt)[c]
Low- and medium-volatile bituminous					
Cheviot	7 455	246	154	30	124
Grande Cache	4 250	199	85	37	48
Subtotal[c]	**11 705**	**445**	**239**	**68**	**171**
High-volatile bituminous					
Coal Valley	17 865	572	331	166	165
Obed	7 590	162	137	46	91
Subtotal[c]	**25 455**	**734**	**468**	**212**	**256**
Subbituminous					
Paintearth	5 120	163	121	105	16
Sheerness	7 000	196	150	95	55
Dodds	425	2.0	2.0	1.6	0.4
Burtonsville Island	150	0.5	0.5	0.2	0.3
Highvale	12 140	1 021	764	421	344
Genesee	7 320	250	176	95	81
Subtotal[c]	**32 155**	**1 633**	**1 214**	**718**	**497**
Total[c]	**69 315**	**2 812**	**1 921**	**998**	**924**

[a] ha = hectares.
[b] Mt = megatonnes; mega = 10^6.
[c] Any discrepancies are due to rounding.

To avoid large fluctuations in ultimate potential from year to year, the AER has adopted the policy of using the figures published in the 2000 edition of *ST31* and adjusting them slightly to reflect the most recent trends. **Table R8.3** gives quantities by rank for surface- and underground-mineable ultimate in-place resources, as well as the ultimate potential. No change to ultimate potential has been made for 2013.

8.2 Supply of and Demand for Marketable Coal

Alberta produces three types of marketable coal: subbituminous, metallurgical bituminous, and thermal bituminous. Subbituminous coal is mainly used to generate electricity in Alberta. Metallurgical bituminous coal is exported and used for industrial applications, such as steel production. Thermal bituminous coal is also exported and used to fuel electricity generators in distant markets. The higher calorific content of thermal bituminous coal makes it possible to economically transport the coal over long distances. While subbituminous coal is burned without any form of upgrading, both types of export coal are sent in raw form to a preparation plant, whose output is referred to as clean coal. Subbituminous raw coal and clean bituminous coal are collectively known as marketable coal.

Table R8.3 Ultimate in-place and potential resources (Gt)[a]

Coal rank Classification	Ultimate in-place	Ultimate potential
Low- and medium-volatile bituminous		
Surface	2.7	1.2
Underground	18	2.0
Subtotal	**21**	**3.2**
High-volatile bituminous		
Surface	10	7.5
Underground	490	150
Subtotal	**500**	**160**
Subbituminous		
Surface	14	9.3
Underground	1 400	460
Subtotal	**1 500**	**470**
Total	**2 000[b]**	**620**

[a] Tonnages have been rounded to two significant figures. Totals are not arithmetic sums but are the result of separate determinations.

[b] Work done by the Alberta Geological Survey suggests that the value is likely significantly larger.

8.2.1 Coal Production – 2013

The locations of coal mine sites in Alberta are shown in **Figure S8.1**. In 2013, ten mine sites produced coal in Alberta, as shown in **Table S8.1**. These mines produced 29.1 megatonnes (Mt) of marketable coal. Subbituminous coal accounted for 79 per cent of the total, metallurgical bituminous coal 10 per cent, and thermal bituminous coal the remaining 11 per cent. In 2013, while metallurgical and thermal bituminous coal production decreased by 3 and 10 per cent, respectively, subbituminous coal increased by 5 per cent relative to 2012. Overall, total marketable production of coal has increased by 3 per cent.

Six surface mines produce subbituminous coal. Most mines serve nearby electric power plants, while a few mines supply residential and commercial customers. Because of the need for long-term supply to power plants, most of the coal reserves are dedicated to the power plants.

Three surface mines and one mine with both surface and underground recovery produce the provincial supply of metallurgical and thermal grade coal.

8.2.2 Coal Production – Forecast

The projected production for each of the three types of marketable coal is shown in **Figure S8.2**. Total production is expected to increase over the forecast period by about 6 per cent, from 29.1 Mt in 2013 to 30.7 Mt in 2023. Subbituminous and metallurgical bituminous coal production is forecast to increase by 7 and 16 per cent, respectively, by 2023, while bituminous thermal coal production will remain flat. An increase in production of both metallurgical and export thermal coal is possible if the approved and proposed mines open within the forecast period.

Figure S8.1

Producing coal mines in Alberta

○ Surface coal mine ● Underground coal mine

Mountain Region
Low- to medium-volatile bituminous coals

① ❶ Grande Cache
② Cheviot

Foothills Region
High-volatile bituminous coals

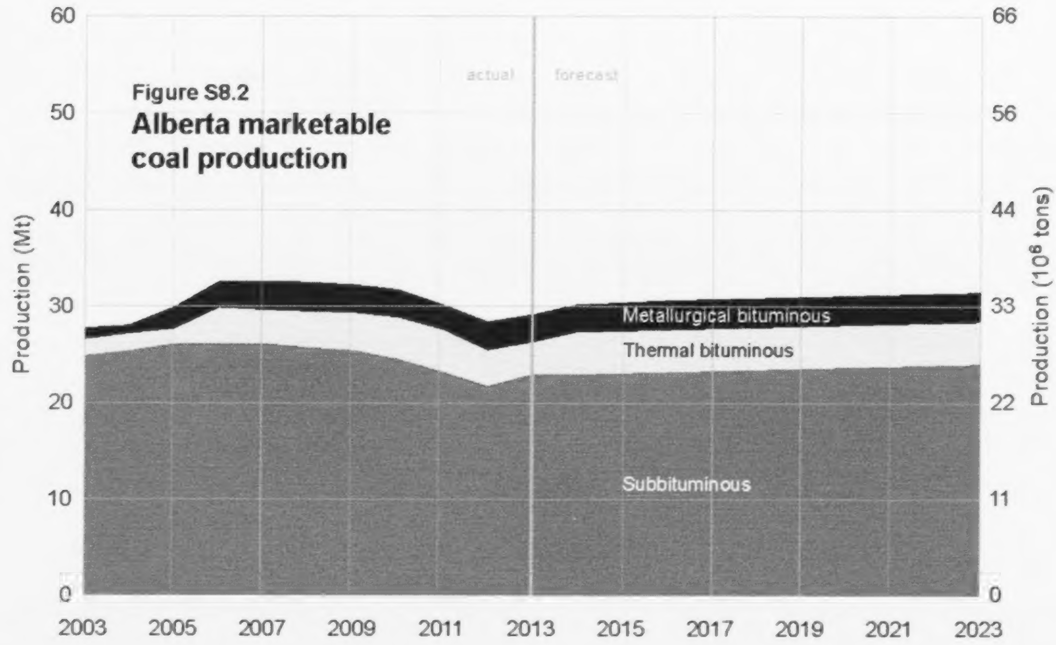
③ Coal Valley
④ Obed

Plains Region
Subbituminous coals

⑤ Highvale
⑥ Burtonsville Island
⑦ Genesee
⑧ Dodds
⑨ Paintearth
⑩ Sheerness

Table S8.1 Alberta coal mines and marketable coal production in 2013

Owner (grouped by coal type)	Mine	Location	Production (Mt)
Subbituminous coal			
Capital Power GP Holdings Inc.	Genesee	Genesee	5.2
Prairie Mines and Royalty Ltd.	Sheerness	Sheerness	4.0
	Paintearth	Halkirk (Cordel)	2.9
TransAlta Corporation	Highvale	Wabamun	10.7
Dodds Coal Mining Co. Ltd.	Dodds	Ryley	0.08
Keephills Aggregate Co. Ltd.	Burtonsville Island	Burtonsville Island	0.03
Subtotal			**22.9**
Bituminous metallurgical coal			
Teck Resources Limited	Cheviot	Mountain Park	1.7
Grande Cache Coal Corp.	Grande Cache	Grande Cache	1.2
Subtotal			**2.9**
Bituminous thermal coal			
Coal Valley Resources Inc.	Coal Valley	Coal Valley	3.2
	Obed	Obed	0.1
Subtotal			**3.3**
Total			**29.1**



8.2.3 Coal Demand

In Alberta, the subbituminous mines primarily serve coal-fired electricity generation plants. The production from these mines can be affected by the commissioning and closures of power generation plants.

In 2012, the federal government issued new regulations for coal-fired plants that require all coal-fired power plants to either be retired by the end of their economic life (after 50 years of operation) or meet stringent emissions requirements. The new federal regulations are scheduled to come into effect in July 2015. The AER has considered this in forecasting the demand for coal.

Sundance Units 1 and 2 returned to service in September and October 2013, respectively. The operator shut down both units in 2010 under a claim of *force majeure* and was ordered by an arbitration panel in 2012 to rebuild them. Combined, the units are capable of generating 560 megawatts (MW). Starting in 2014, the two units have been included in the AER's demand forecast. Additionally, the upgrade to increase the capacity of Keephills 3 by 13 MW was completed in 2013.

Alberta's metallurgical coal primarily serves the Asian steel industry, with Japan and now China being the leading importers of Alberta coal. Japan also imports the most thermal coal from Alberta. The long distance required to transport coal from mine to port creates a competitive disadvantage for Alberta's export-coal producers. However, the demand for metallurgical coal exports increased by 21 per cent in 2013 from the 2012 level and exports of North American metallurgical coal are becoming more attractive. Consequently, the AER expects a 16 per cent increase in Alberta metallurgical coal production over the forecast period.

9 INFRASTRUCTURE

The infrastructure needed to support the development of Alberta's vast energy resources involves networks of oil and gas pipelines, railroad lines, roads and highways, and electricity transmission lines. This infrastructure also includes facilities that turn raw natural resources into marketable energy products that travel through pipelines and on railroads and trucks to distribution outlets for purchase. Alberta's energy resource infrastructure allows secure and stable access to energy, which helps meet the needs of commercial, residential, and industrial consumers.

HIGHLIGHTS

A new section on infrastructure related to energy resources used to produce and deliver energy commodities to markets in Alberta and beyond.

In Alberta, about 495 gas processing plants, 10 fractionation plants, and 9 straddle plants were active in 2013.

The AER regulates about 415 000 kilometres of pipelines in Alberta.

9.1 Energy Commodity Transportation

Thousands of kilometres of transportation infrastructure are needed to move Alberta's energy resource commodities from where they are produced to where they are consumed. A network of pipelines has been built solely to transport energy resources. Other infrastructure, such as railroads, roads, and electrical lines, is shared with other industries and individual Albertans.

9.1.1 Pipelines

About 415 000 kilometres (km) of pipeline in Alberta are regulated by the AER, which includes about 11 500 km of Alberta Utilities Commission (AUC) natural gas utility pipelines that the AER conducts surveillance and inspections, incidence response, and failure investigations through a memorandum of understanding. Ex-Alberta pipelines are regulated by the National Energy Board (NEB) and include about 71 000 km across Canada.

Alberta's intraprovincial pipeline system is highly integrated and includes gathering, transmission, and distribution lines that transport hydrocarbons from the field to major distribution and processing centres that operate within the province's borders. Removal pipelines are typically long distance, higher capacity pipelines that carry hydrocarbons to ex-Alberta markets. Removal pipelines link Alberta to markets in the rest of Canada and the United States.

9.1.1.1 Crude Oil and Bitumen Pipelines

Current and proposed pipeline infrastructure play a key role in moving Alberta's growing supply of crude oil and bitumen to markets both inside and outside of the province.

To keep up with the rise in production in Alberta, pipeline companies have announced several intraprovincial and removal pipeline projects designed to help

expand capacity in the province and to reach new markets. Midstream companies are also working towards expanding natural gas liquid (NGL) infrastructure in the province to ensure the stable supply of pentanes plus (a diluent for bitumen blending) and ethane (a primary feedstock for the petrochemical sector).

Within the province, the construction of new pipelines and expansion of existing pipelines will ensure that projects have access to traditional hubs in Edmonton and Hardisty and producers have access to ex-Alberta markets.

Table 9.1 shows existing major intraprovincial crude oil and bitumen pipelines in Alberta in 2013. A number of additional intraprovincial pipelines have been planned or announced.

Access Pipeline Inc. intends to twin its existing pipeline, with the new pipeline being capable of transporting 55.6 thousand (10^3) metres per day (m^3/d). The line is scheduled to be in service by 2015.

Enbridge Inc. (Enbridge) also intends to expand its capacity to move bitumen from the Christina Lake region. To do this, it plans to expand the capacity of its Athabasca system, which moves product to the Hardisty Terminal. Additionally, Enbridge has announced that the Fort Hills pipeline system has been commercially secured, with construction to follow customer timing.

Table 9.1 Alberta's intraprovincial crude oil and bitumen pipelines

Name	Destination	Capacity (10^3 m^3/d)
Access Pipeline Inc.		
Access pipeline	Edmonton	23.8
Canadian Natural Resources Limited		
Echo pipeline	Hardisty	12.0
Enbridge Inc.		
Athabasca pipeline	Hardisty	54.8
Waupisoo pipeline	Edmonton	87.4
Husky Energy Inc.		
Husky pipeline	Hardisty; Lloydminster	78.0
Inter Pipeline Fund		
Cold Lake pipeline	Hardisty; Edmonton	103.3
Corridor pipeline	Edmonton	73.9
Pembina Pipeline Corporation		
Horizon pipeline	Edmonton	39.7
Plains Midstream Inc.		
Rainbow pipeline	Edmonton	31.7
Suncor Energy Inc.		
Oil Sands pipeline	Edmonton	23.0
Syncrude Canada Ltd.		
Syncrude Pipeline	Edmonton	61.8

Inter Pipeline Fund (Inter Pipeline) has announced that it intends to proceed with an integrated expansion of its Cold Lake and Polaris pipeline systems.

Table 9.2 shows existing removal crude oil and bitumen pipelines in Alberta in 2013. A number of additional removal pipelines have been planned or announced.

Enbridge, pending approval from the federal government, intends to develop the Northern Gateway pipeline, which would see production move from Bruderheim, Alberta, to Kitimat, British Columbia. The pipeline would have a capacity of 83.3 10^3 m^3/d.

Kinder Morgan Canada (Kinder Morgan) has filed an application with the NEB to expand its TransMountain pipeline from 47.7 10^3 m^3/d to 141.4 10^3 m^3/d. Where possible, the expansion is planned to follow existing routing, running from Edmonton, Alberta, to the greater Vancouver area.

The northern leg of TransCanada Corporation's (TransCanada's) Keystone XL project, pending approval from the U.S. State Department, is expected to run from Hardisty, Alberta, to Steele City, Nebraska. The pipeline would have a capacity of 131.9 10^3 m^3/d.

TransCanada is currently gauging interest in the conversion of part of its mainline system from gas transmission to oil, and plans to file an application in 2014. The converted pipeline, referred to as the Energy East project, would carry 174.8 10^3 m^3/d and would initially move oil from Alberta to Montreal.

Table 9.2 Alberta's removal crude oil and bitumen pipelines

Name	Destination	Capacity (10^3 m^3/d)
Enbridge Inc.		
Enbridge pipeline	Eastern Canada U.S. East Coast U.S. Midwest	301.9
Alberta Clipper pipeline	U.S. Midwest	71.5
Kinder Morgan Canada		
Express pipeline	U.S. Rocky Mountains U.S. Midwest	44.9
Trans Mountain pipeline	British Columbia U.S. West Coast Offshore	47.7
Plains Midstream Canada		
Milk River pipeline	U.S. Rocky Mountains	18.8
Pacific Energy Partners, L.P.		
Rangeland pipeline	U.S. Rocky Mountains	13.5
TransCanada Corporation		
Keystone pipeline	U.S. Midwest	93.8

9.1.1.2 Natural Gas Liquids Pipelines

The petrochemical industry in Alberta is the main consumer of ethane recovered from natural gas, with four ethylene plants using ethane as feedstock. Three of these plants are located at Joffre, Alberta, with the fourth located at Fort Saskatchewan. The Alberta Ethane Gathering System (AEGS) transports specification ethane to the Joffre and Fort Saskatchewan areas.

Demand for pentanes plus has been exceeding Alberta supply since 2004, resulting in a reliance on alternative sources (imports) of pentanes plus for use as diluent. Alberta's imports of pentanes plus are expected to continue to increase over the next 10 years with growing demand from the oil sands. Currently, Alberta imports pentanes plus on trucks, rail cars, and pipelines.

Table 9.3 shows existing intraprovincial NGL pipelines in Alberta in 2013. A number of additional intraprovincial pipelines have been planned or announced.

Enbridge is proposing to construct and operate a new condensate pipeline, the Norlite pipeline, which will carry condensate from the company's Stonefell site to its Athabasca and Norealis terminals near Fort McMurray.

Inter Pipeline announced that it plans to expand its Polaris pipeline system to provide diluent service to northern Alberta. Once complete, the company plans to increase the capacity on the Polaris pipeline from 9.5 10^3 m^3/d to 19.1 10^3 m^3/d, with an expected start-up date of the first quarter of 2015.

Table 9.3 Alberta's intraprovincial NGL pipelines

Name	Destination	Capacity (10^3 m^3/d)
Inter Pipeline Fund		
Polaris pipeline	Northern Alberta	9.5
Pembina		
Pembina pipeline	Gathering pipelines in south-central Alberta	23.8
Swan Hills pipeline	Edmonton	17.5
Mitsue pipeline	North of Slave Lake	7.2
Brazeau/Caroline pipelines	Edmonton	9.5
Cremona pipeline	Rangeland pipeline in southern Alberta	7.9
Bonnie Glen pipeline	Edmonton	15.9
Inter Pipeline Fund		
Rainbow pipeline	Edmonton	35.0
Rangeland pipeline	Carway	7.9
Co-Ed pipeline system	Edmonton; Fort Saskatchewan	11.4
Veresen Inc.		
Alberta ethane gathering system	Petrochemical facilities in Alberta	51.2
Williams		
Boreal pipeline	Redwater	19.8

Keyera Corp's (Keyera's) proposed Alberta Liquids pipeline system would enable producers to transport NGL mix and condensates from the Simonette/Edson area to Fort Saskatchewan. Construction on Keyera's Wilson Creek pipeline has begun and will be capable of carrying about 4.0 10^3 m^3/d of condensate to its Rimbey gas plant. In addition, Keyera has also started work on its Wapiti pipeline system. The system will consist of a 12-inch raw sour gas gathering pipeline and a six-inch segregated condensate line and will extend from the Wapiti area to the Simonette gas plant. Keyera expects to complete the pipeline in the second quarter of 2014.

Pembina Pipeline Corporation's (Pembina's) proposed Cornerstone pipeline would consist of two 320 km pipelines and related infrastructure to provide KKD Oil Sands Partnership with diluent and blended bitumen transportation services associated with enhanced oil recovery in northeast Alberta. The company expects a start-up date of mid-2017. In addition, Pembina's Phase II NGL Expansion, which it announced in November 2012, will add an additional 8.4 10^3 m^3/d of capacity to the Northern NGL pipeline system by mid-2015.

Pembina has also proposed a Phase III Expansion that would involve constructing 270 km of pipeline from Fox Creek, Alberta, to the Edmonton area. The pipeline would have an initial capacity of 50.9 10^3 m^3/d and an ultimate capacity of over 79.5 10^3 m^3/d once pump stations have been added. It has announced an in-service date of 2017.

Plains Midstream Canada (Plains) announced plans to build a new pipeline, the Rainbow II, which would connect to Enbridge's existing terminal near Edmonton and to Plains's existing Nipisi Terminal in northwestern Alberta. The new pipeline would be located within Plain's Rainbow pipeline right-of-way.

Table 9.4 shows existing removal and import NGL pipelines in Alberta in 2013.

Kinder Morgan Energy Partners, L.P. is planning to reverse the western leg of its Cochin pipeline to supply condensate from Kankakee County, Illinois, to Fort Saskatchewan, Alberta. Light condensate shipments could begin in July 2014.

9.1.1.3 Natural Gas Pipelines

Natural gas is transported from the wellhead by a gathering system to field processing plants. Field plants, typically located near the source of the gas upstream of the pipeline, process the raw natural gas by removing impurities, such as water and hydrogen sulphide. NGLs may also be extracted from the raw gas stream.

Once impurities are extracted and the natural gas meets pipeline specification, the natural gas is then compressed before being transported into a large transmission pipeline. Under compression, natural gas is able to flow through the transmission system from areas of high pressure to areas of low pressure. Once natural gas reaches end markets, local distribution companies reduce the pressure for local delivery distribution networks.

Table 9.5 shows existing intraprovincial natural gas pipelines in Alberta in 2013. No new major intraprovincial natural gas pipeline projects have been announced recently.

Table 9.6 shows existing removal and import natural gas pipelines in Alberta in 2013. No new major removal or import natural gas pipeline projects have been announced recently.

Table 9.4 Alberta's removal and import NGL pipelines

Name	Destination[a]	Capacity (10^3 m^3/d)
Enbridge		
Southern Lights pipeline	Edmonton	28.6
Kinder Morgan		
Cochin pipeline	Sarnia, Ontario	15.1
Pembina		
Peace and Northern NGL pipeline system	Fort Saskatchewan	57.5
Liquids gathering system	Pembina Northern NGL pipeline system	6.1
Vantage Pipeline		
Vantage pipeline	AEGS in southern Alberta	6.3

[a] All destinations are within Alberta's boundaries, unless noted otherwise.

Table 9.5 Alberta's intraprovincial natural gas pipelines

Name	Destination	Capacity (10^6 m^3/d)
ATCO		
ATCO system	A gathering system in central Alberta	107.1
Suncor		
Suncor pipeline	Ft. McMurray	2.8
TransCanada		
NOVA Gas Transmission Ltd. (AB-BC border)	A network of natural gas pipelines with multiple receipt and delivery points within Alberta and at provincial borders.	63.9
NOVA Gas Transmission Ltd. (AB-Montana border)	A network of natural gas pipelines with multiple receipt and delivery points within Alberta and at provincial borders.	3.1
Foothills (Alberta system)	BC border	63.9
Enbridge		
Alliance[a]	Steelman, Saskatchewan	130.5

[a] Current contracted capacity.

Table 9.6 Alberta's removal and import natural gas pipelines

Name	Destination	Capacity (10^6 m^3/d)
Enbridge		
Alliance[a]	Guardian, Illinois	47.9
TransCanada		
Mainline	Quebec-Vermont border	197.2
Foothills (BC)	Foothills (BC border)	84.5
Foothills (SK)	Foothills (SK border)	65.7

[a] Total contract capacity.

9.1.2 Railroads

North America's railroad network is extensive, linking almost all major cities and ports across the continent. The extent to which this rail network is interconnected allows not only movement across borders, but also across markets. Where pipelines offer shippers the ability to only access certain markets, rail allows producers to place their product on cars and ship it almost anywhere on the continent serviced by rail.

Alberta's existing railroad system crosses major oil producing regions in the province and has become more efficient due to new infrastructure, including pipeline-connected tanks-to-rail unit train service. The railroads connecting Alberta to ports in British Columbia have been strengthened to transport large unit trains of coal and other commodities. The railroad system also allows access to all eastern Canadian refineries for both oil and NGLs as well as access to seaway distribution terminals in Quebec. Access to both the Canadian west and east coasts, including access to the U.S. Gulf Coast, allows Albertan producers to connect to global markets.

Major existing and proposed rail infrastructure related to oil and gas development in Alberta is as follows:

- In 2013, Canexus Corporation finished expanding its rail terminal capacity at its Bruderheim facility, northeast of Edmonton. The facility should provide rail access to bitumen producers and is connected to both the Canadian National Railway Company (CN) and Canadian Pacific Railway Limited (CP).
- Gibson expects to open its proposed Hardisty rail terminal in 2014, which is intended to handle crude oil and is connected to the CP railway system.
- In September 2013, Keyera completed construction of the Southern Cheecham rail and truck terminal located near Fort McMurray. The facility is capable of offloading diluent delivered by rail. Currently, Canada's two main rail providers handle diluent at Keyera's Alberta Diluent Terminal in Edmonton, in addition to shipping crude oil from the Bakken play in Saskatchewan.
- Keyera also plans on constructing a rail terminal at Josephburg near Fort Saskatchewan to optimize propane movement out of western Canada. The project's start-up date is the second half of 2015.
- Kinder Morgan's Edmonton Rail Terminal, also slated to open in 2014, is intended to handle crude oil and provide access to both CN and CP rail systems.

In 2014, the Government of Canada put rules in place on older Dot-111 rail cars used to transport petroleum products. The rules require the retirement or retrofitting of existing cars within three years.

9.1.3 Highways

Starting with only a few major roads in 1905, Alberta's road network has expanded to include thousands of kilometres of paved and unpaved roads. Alberta currently has 31 000 km of highway that connect into highway systems in bordering Canadian provinces and territories as well as the United States. Highways help in the growth of the economy by facilitating the distribution of different commodities and goods all over the country and serve as important links to airways, waterways, and railways. Alberta's highways serve population centres, provincial and international border crossings, airports, transportation facilities, and major commerce hubs.

9.2 Plants and Facilities

The downstream sector of the oil and gas industry involves the refining of crude oil and raw natural gas produced by the upstream sector as well as the marketing of such refined products. Alberta produces an array of different marketable energy commodities such as propane, butane, diesel, naphtha, and gasoline.

9.2.1 Processing Plants – Oil Refineries

Oil refineries use crude oil, butanes, and natural gas as feedstock, along with upgraded and nonupgraded bitumen and pentanes plus, to produce a wide variety of refined petroleum products (RPPs). The key determinants of crude oil feedstock requirements for Alberta refineries are domestic Albertan demand for RPPs, shipments to other western Canadian provinces, exports to the United States, and competition from other feedstocks. **Table 9.7** lists the capacities of Alberta's four refineries in 2013.

9.2.2 Processing Plants – Natural Gas

Ethane and other NGLs are recovered mainly from the processing of natural gas. Gas reprocessing plants, often referred to as straddle plants, recover NGL components or NGL mix from marketable gas. They are usually located on rate-regulated main gas transmission pipelines at border delivery points. Straddle plants remove much of the propane plus (C_3+) and ethane volumes, with the degree of recovery being determined by the plant's extraction capability, contractual arrangements, and product demand.

Field plants may send recovered NGL mix to centralized, large-scale fractionation plants where the mix is fractionated into specification products such as propane, butanes, and pentanes plus. A de-ethanizer tower along with a turbo expander chill the natural gas to isolate ethane from other NGLs.

In Alberta, DOW Chemical Company's (DOW's) Fort Saskatchewan fractionator and Pembina's Redwater fractionator separate ethane from the NGL stream. Ethane recovered at field processing plants, NGL fractionators, and straddle plants is shipped on the AEGS to the Alberta ethane market, mainly the petrochemical sector.

In Alberta, there are about 495 active gas processing plants that recover NGL mix or specification products, 10 fractionation plants that fractionate NGL mix streams into specification products, and 9 straddle plants.

Alberta's straddle plants and fractionation plants are listed in **Tables 9.8** and **9.9**.

Alberta's petrochemical industry is the major consumer of ethane, which is used in the production of ethylene and polyethylene. Ethylene is one of the building blocks used to produce products such as packaging material, ethylene glycol, and styrene. The petrochemical industry also produces many other products such as fertilizer.

Petrochemical plants in Alberta are mainly located in Joffre and Fort Saskatchewan and represent one of the largest manufacturing industries. Alberta has four ethane-cracking plants, of which two are the world's largest, with a combined capacity of 3.9 million tonnes of ethylene per year.

Table 9.7 Alberta refinery capacity in 2013 (m^3/d)

Refinery	Capacity
Imperial Edmonton	29 700
Petro-Canada Edmonton	22 600
Shell Scotford (in Fort Saskatchewan)	15 900
Husky Lloydminster	4 500

Table 9.8 Straddle plants in Alberta

Area	Operator
Empress	Spectra Energy Empress Management
Empress	Plains Midstream Canada ULC
Cochrane	Inter Pipeline Extraction Ltd.
Ellerslie (Edmonton)	AltaGas Ltd.
Empress	ATCO Energy Solutions Ltd.
Fort Saskatchewan	ATCO Energy Solutions Ltd.
Empress	1195714 Alberta Ltd.
Joffre	AltaGas Ltd.
Atim (Villeneuve)	ATCO Energy Solutions Ltd.

Table 9.9 Fractionation plants in Alberta

Area	Operator
Plains Buck Creek	Plains Midstream Canada ULC
Fort Saskatchewan	Keyera Energy Ltd.
Hardisty (Killam)	Gibson Energy ULC
Fort Saskatchewan	Plains Midstream Canada ULC
Kemp[1]	Stittco Energy Limited
Fort Saskatchewan	Dow Chemical Canada ULC
Redwater	Pembina NGL Corporation
High Prairie	Plains Midstream Canada ULC
Harmattan-Elkto N	Taylor Processing Inc.
Carrot Creek	Tervita Corporation

[1] Last volumetric activity was April 2013.

9.2.3 Processing Plants – Upgraders

Upgraders allow producers to take advantage of heavy and light oil differentials by processing bitumen into various grades of synthetic crude oil, allowing bitumen to reach a wider variety of markets. Alberta's five upgraders produce a variety of upgraded products: light sweet and medium sour crudes, including diesel (Suncor); light sweet synthetic crude (Syncrude, CNRL, and Nexen); and sweet and heavy synthetic oil and intermediate refinery feedstock (Shell). **Table 9.10** shows average upgraded bitumen production in 2013.

9.2.4 Electricity Infrastructure

As of December 31, 2013, Alberta's installed generation capacity, as set out on the Alberta Electric System Operator's (AESO's) website, includes 6271 megawatts (MW) of coal-fired, 5892 MW of gas-fired, 1088 MW of wind-powered, 894 MW of hydro-powered, and 423 MW of other (e.g., biomass, biogas, and solar), for a total installed capacity of 14 568 MW.

In 2013, according to AESO, 71 per cent of the natural gas–fired capacity in the province was classified as cogeneration. Cogeneration is the combined production of electricity and thermal energy using natural gas as the fuel source. Thermal energy is often used for manufacturing, heating, producing steam for in situ oil production, refining, and upgrading.

Alberta's electricity system has about 26 000 km of transmission lines. It's connected to systems in British Columbia, Saskatchewan, and Montana. These three interties allow Alberta to import or export electricity. In addition to the transmission interties, a natural gas–fired electricity generation unit in Fort Nelson (northern British Columbia) supplies power to the surrounding communities and sells surplus electricity into the Alberta grid.

Table 9.10 Average upgraded bitumen production, 2013[a]

Company/project name	Production (10^3 m^3/d)
Syncrude	43.6
Suncor	45.9
Shell Canada Scotford	37.7
CNRL Horizon	16.0
Nexen Long Lake	5.6
Total	**148.8**

[a] Any discrepancies are due to rounding.

Appendix A Terminology and Conversion Factors

Terminology

Alberta Natural Gas Reference Price (ARP)	A monthly weighted average field price of all Alberta gas sales that is used for royalty purposes. The price is determined by the Alberta Department of Energy through a survey of actual sales transactions. Also known as the price of Alberta natural gas at the plant gate.
API gravity	A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.
Brent Blend (Brent)	A grade of light sweet crude oil derived from a mix of 15 different oil fields in the North Sea. Brent blend futures are traded on the Intercontinental Exchange Inc. (ICE) and are considered a global benchmark for oil prices.
Burner-tip	The location where a fuel is used by a consumer.
Butanes	In addition to its normal scientific meaning, a mixture mainly of butanes that ordinarily may contain some propane or pentanes plus (*Oil and Gas Conservation Act*, section 1(1)(j)).
Coalbed methane (CBM)	Naturally occurring dry gas, predominantly methane, produced during the transformation of organic matter into coal.
Cogeneration gas plant	A gas-fired plant used to generate both electricity and steam.
Commingled	Commingled flow describes the production of fluid from two or more separate zones through a single conduit.
Compressibility factor	A correction factor for non-ideal gas determined for gas from a pool at its initial reservoir pressure and temperature and, where necessary, including factors to correct for acid gases.
Condensate	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that (i) is recovered or is recoverable at a well from an underground reservoir and may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured or estimated, or (ii) is recovered from an in situ coal scheme and is liquid at the conditions under which its volume is measured or estimate (*Oil and Gas Conservation Act*, section 1(1)(k)).
Crude bitumen	A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its naturally occurring viscous state, will not flow to a well (*Oil Sands Conservation Act*, section 1(1)(c)).
Crude oil (conventional)	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate or crude bitumen (*Oil and Gas Conservation Act*, section 1(1)(o)).
Crude oil (heavy)	Crude oil with a density of 900 kg/m^3 or greater.

Crude oil (light–medium)	Crude oil with a density less than 900 kg/m^3.
Crude oil (synthetic)	A mixture, mainly of pentanes and heavier hydrocarbons, that may contain sulphur compounds, and is derived from crude bitumen and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so derived (*Oil and Gas Conservation Act*, section 1(1)(zz)).
Crude oil netback	An economic indicator of profitability expressed as a dollar value per unit of production. Crude oil netbacks are calculated from the price of West Texas Intermediate (WTI) crude oil at Chicago less transportation and other charges to supply crude oil from the wellhead to the Chicago market. Alberta netback prices are adjusted for the U.S./Canadian dollar exchange rate, as well as crude quality differences.
Datum depth	The approximate average depth relative to sea level of the midpoint of an oil or gas productive zone for the wells in a pool.
Decline rate	The annual rate of decline in well productivity.
Deep-cut facility	See NGL recovery (deep-cut gas facility).
Density	The mass or amount of matter per unit volume.
Density, relative (raw gas)	The density relative to air of raw gas upon discovery, determined by an analysis of a gas sample representative of a pool under atmospheric conditions.
Development entity (DE)	An administrative unit consisting of multiple formations in a designated area described in an order of the AER. Within the DE gas may be produced without segregation in the wellbore, subject to certain criteria specified in section 3.051 of the *Oil and Gas Conservation Rules*.
Diluent	Lighter viscosity petroleum products that are used to dilute crude bitumen for transport in pipelines.
Discovery year	The year when drilling was completed for the well in which the oil or gas pool was discovered.
Economic strip ratio	Ratio of waste (overburden material that covers mineable ore) to ore (in this report refers to coal or oil sands) used to define an economic limit below which it is economical to remove the overburden to recover the ore.
Established reserves	Those reserves recoverable under current technology and present and anticipated economic conditions specifically proved by drilling, testing, or production, plus the portion of contiguous recoverable reserves that are interpreted to exist from geological, geophysical, or similar information with reasonable certainty.
Ethane	In addition to its normal scientific meaning, a mixture mainly of ethane that ordinarily may contain some methane or propane (*Oil and Gas Conservation Act*, section 1(1)(s)).
Extraction	The process of liberating hydrocarbons (e.g., propane, bitumen) from their source (e.g., raw gas, mined oil sands).
Feedstock	A raw material supplied to a refinery, oil sands upgrader, or petrochemical plant.
Field	(i) The general surface area or areas underlain or appearing to be underlain by one or more pools, or (ii) the subsurface regions vertically beneath a surface area or areas referred to in subclause (i) (*Oil and Gas Conservation Act*, section 1(1)(x)).

Field (gas) plant	A natural gas facility that processes raw gas and produces a marketable product that meets pipeline specifications. These plants, located near the gas source, remove impurities, such as water and hydrogen sulphide, from the raw gas stream and may also extract natural gas liquids. See also NGL recovery (extraction plant).
Field plant gate	The point at which the gas exits the field plant and enters a pipeline.
Fractionation plant	See NGL recovery (fractionation plant)
Gas	Raw gas, synthetic coal gas or marketable gas or any constituent of raw gas, synthetic coal gas, condensate, crude bitumen or crude oil that is recovered in processing and that is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, section 1(1)(y)).
Gas (associated)	Gas in a free state in communication in a reservoir with crude oil under initial reservoir conditions.
Gas (dry)	Raw or processed gas that contains little to no natural gas liquids.
Gas (liquids-rich)	Raw gas that contains a relatively high concentration of natural gas liquids.
Gas (marketable)	A mixture mainly of methane originating from raw gas, if necessary through the processing of the raw gas for the removal or partial removal of some constituents, and that meets specifications for use as a domestic, commercial or industrial fuel or as an industrial raw material (*Oil and Gas Conservation Act*, section 1(1)(ee)). Marketable gas is measured at standard conditions of 101.325 kPa and 15°C.
Gas (nonassociated)	Gas that is not in communication in a reservoir with an accumulation of liquid hydrocarbons at initial reservoir conditions.
Gas (raw)	A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium and minor impurities, or some of them, that is recovered or is recoverable at a well from an underground reservoir and is gaseous at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, section 1(1)(tt)).
Gas (solution)	Gas that is dissolved in crude oil under reservoir conditions and evolves as a result of pressure and temperature changes.
Gas (wet)	Raw or processed gas that contains natural gas liquids.
Gas-oil ratio (initial solution)	The volume of gas (in cubic metres, measured under standard conditions) contained in one stock-tank cubic metre of oil under initial reservoir conditions.
Good production practice (GPP)	Production of crude oil or raw gas at a rate (i) not governed by a base allowable, but (ii) limited to what can be produced without adversely and significantly affecting conservation, the prevention of waste, or the opportunity of each owner in the pool to obtain his share of production (*Oil and Gas Conservation Rules*, section 1.020(2)9). This practice is authorized by the AER either to improve the economics of production from a pool and thus defer its abandonment or to avoid unnecessary administrative expense associated with regulation or production restrictions where this serves little or no purpose.
Gross heating value (of dry gas)	The heat liberated by burning moisture-free gas at standard conditions and condensing the water vapour to a liquid state.

Henry Hub	A distribution hub on a main natural gas pipeline system in the United States near Erath, Louisiana. It is the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX).
Horizontal well	A well in which the lower part of the wellbore is drilled parallel to the zone of interest.
Initial established reserves	Established reserves prior to the deduction of any production.
Initial volume in-place	The volume or mass of crude oil, crude bitumen, raw natural gas, or coal calculated or interpreted to exist in the ground before any quantity has been produced.
Maximum day rate	The operating day rate for gas wells when they are first placed on production. The estimation of the maximum day rate requires the average hourly production rate. For each well, the annual production is divided by the hours that the well produced in that year to obtain the average hourly production for the year. This hourly rate is then multiplied by 24 hours to yield an estimate of a full-day operation of a well, which is referred to as the maximum day rate.
Maximum recoverable thickness	The assumed maximum operational reach of underground coal mining equipment in a single seam.
Mean formation depth	The approximate average depth below kelly bushing of the midpoint of an oil or gas productive zone for the wells in a pool.
Methane	In addition to its normal scientific meaning, a mixture mainly of methane that ordinarily may contain some ethane, nitrogen, helium, or carbon dioxide (*Oil and Gas Conservation Act*, section 1(1)(ff)).
Multilateral well	A well where two or more production holes, usually horizontal in direction with reference to the zone of interest, are drilled from a single surface location.
Natural gas liquids (NGLs)	Ethane, propane, butanes, pentanes plus, or a combination of these obtained from the processing of raw gas or condensate.
NGL recovery (deep-cut gas facility)	A natural gas processing facility capable of extracting ethane and other natural gas liquids.
NGL recovery (extraction plant)	A natural gas processing facility that can remove natural gas liquids from raw or processed natural gas. Extraction plants can remove an NGL mix, but cannot split the natural gas liquids into separate components. See also field (gas) plant.
NGL recovery (fractionation plant)	A natural gas processing facility that takes a natural gas liquids stream and separates out its different components: ethane, propane, butane, and pentanes plus.
NGL recovery (shallow-cut gas facility)	A natural gas processing facility that extracts propane, butane, and pentanes plus.
NGL recovery (straddle plant)	A reprocessing plant on major natural gas transmission lines near Alberta's borders that extracts natural gas liquids from marketable gas. Most plants are deep-cut facilities that then ship an NGL stream to fractionation plants in central Alberta.
Off-gas	Natural gas produced from upgrading bitumen. This gas is typically rich in natural gas liquids and olefins.

Oil Condensate, crude oil, or synthetic coal liquid or a constituent of raw gas, condensate, or crude oil that is recovered in processing, that is liquid at the conditions under which its volume is measured or estimated (*Oil and Gas Conservation Act*, section 1(1)(hh)).

Oil sands (i) sands and other rock materials containing crude bitumen,
(ii) the crude bitumen contained in those sands and other rock materials, and
(iii) any other mineral substances, other than natural gas, in association with that crude bitumen or those sands and other rock materials referred to in subclauses (i) and (ii) (*Oil Sands Conservation Act*, section 1(1)(l)).

Oil sands deposit A natural reservoir containing or appearing to contain an accumulation of oil sands separated or appearing to be separated from any other such accumulation (*Oil and Gas Conservation Act*, section 1(1)(jj)).

Overburden When used in reference to mining, overburden is the thickness of the material above a mineable occurrence of coal or bitumen; otherwise, it is the soil and loose material between the land's surface and solid bedrock.

Pay thickness (average) The bulk rock volume of a reservoir of crude oil, bitumen, or gas divided by its area.

Pentanes plus A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and that is obtained from the processing of raw gas, condensate or crude oil (*Oil and Gas Conservation Act*, section 1(1)(mm)).

Pool (i) a natural underground reservoir containing or appearing to contain an accumulation of oil or gas, or both, separated or appearing to be separated from any other such accumulation, or
(ii) in respect of an in situ coal scheme, that portion of a coal deposit that has been or is intended to be converted to synthetic coal gas or synthetic coal liquid (*Oil and Gas Conservation Act*, section 1(1)(oo)).

Porosity The effective pore space of the rock volume determined from core analysis and well log data measured as a fraction of rock volume.

Pressure (initial) The reservoir pressure at the reference elevation of a pool upon discovery.

Propane In addition to its normal scientific meaning, a mixture mainly of propane that ordinarily may contain some ethane or butanes (*Oil and Gas Conservation Act*, section 1(1)(rr)).

Recovery (enhanced) The increased recovery from a pool achieved by artificial means or by the application of energy extrinsic to the pool, which artificial means or application includes pressuring, cycling, pressure maintenance or injection to the pool of a substance or form of energy, but does not include the injection in a well of a substance or form of energy for the sole purpose of
(i) aiding in the lifting of fluids in the well, or
(ii) stimulation of the reservoir at or near the well by mechanical, chemical, thermal or explosive means (*Oil and Gas Conservation Act*, section 1(1)(r)).

Recovery (pool) In gas pools, the fraction of the in-place resources of gas expected to be recovered under the subsisting recovery mechanism.

Recovery (primary) Recovery of oil by natural depletion processes only, measured as a volume that is recovered or as a fraction of the in-place oil.

Refined petroleum products End products in the refining process.

Refinery light ends	Light oil products produced at a refinery; includes gasoline and aviation fuel.
Remaining established reserves	Initial established reserves less cumulative production.
Reprocessing facilities	Gas processing plants used to extract ethane and natural gas liquids from marketable natural gas. Such facilities, also referred to as straddle plants, are located on major natural gas transmission lines.
Reservoir	A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) that is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.
Sales gas	A volume of gas transacted in a time period. This gas may be augmented with gas from storage.
Saturation (gas)	The fraction of pore space in the reservoir rock occupied by gas upon discovery.
Saturation (water)	The fraction of pore space in the reservoir rock occupied by water upon discovery.
Shale gas	The naturally occurring gas produced from organic-rich, fine-grained rocks.
Shale NGLs	The naturally occurring mixture of natural gas liquids produced from organic-rich, fine-grained rocks.
Shale oil	A naturally occurring mixture of mainly pentanes and heavier hydrocarbons produced from organic-rich, fine-grained rocks.
Shrinkage factor (initial)	The volume occupied by one cubic metre of oil from a pool measured at standard conditions after flash gas liberation consistent with the surface separation process and divided by the volume occupied by the same oil and gas at the pressure and temperature of a pool upon discovery.
Solvent	A suitable mixture of hydrocarbons ranging from methane to pentanes plus but consisting largely of methane, ethane, propane, and butanes for use in enhanced-recovery operations.
Specification product	A crude oil or refined petroleum product with defined properties.
Sterilization	The rendering of otherwise definable economic ore as unrecoverable.
Straddle plant	See NGL recovery (straddle plant).
Strike area	An administrative geographical boundary used in relation to potential resource accumulations.
Strip ratio	The amount of overburden that must be removed to gain access to a unit amount of coal. A stripping ratio may be expressed as (1) the thickness of overburden to the thickness of coal, (2) the volume of overburden to the volume coal, (3) the weight of overburden to the weight of coal, or (4) the cubic yards of overburden to tons of coal. Stripping ratios are commonly used to express the maximum thickness, volume, or weight of overburden that can be profitably removed to obtain a unit amount of coal.
Successful wells drilled	Wells drilled for gas or oil that are cased and not abandoned at the time of drilling.

Surface loss	A sum of the fractions of recoverable gas that is removed as acid gas and liquid hydrocarbons, and gas that is used as lease or plant fuel or that is flared.
Synthetic crude oil (SCO)	See crude oil (synthetic).
Temperature	The initial reservoir temperature upon discovery at the reference elevation of a pool.
Ultimate potential	An estimate of the initial established reserves that will have been developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions through extensions and revisions to existing pools and the discovery of new pools. For hydrocarbons, ultimate potential volumes can be determined by the following simple equation: ultimate potential = initial established reserves + additions to existing pools + future discoveries.
Upgraded bitumen	A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from oil sands. Generally considered to be equivalent to synthetic crude oil (SCO) but can also include refined petroleum products.
Upgrading	A process that converts bitumen and heavy crude oil into a mixture of lighter hydrocarbons by removing carbon or adding hydrogen.
Western Canadian Select (WCS)	A grade of heavy crude oil derived from of a mix of heavy crude oil and crude bitumen blended with diluents. The price of WCS is often used as a representative price for Canadian heavy crude oils.
West Texas Intermediate (WTI)	A light sweet crude oil that is typically referenced for pricing at Cushing, Oklahoma.
Zone	Any stratum or sequence of strata that is designated by the AER as a zone (*Oil and Gas Conservation Act*, section 1(1)(ggg)).

PSAC Areas

The Petroleum Services Association of Canada (PSAC) has sectioned Canada into a number of geographic regions based on the predominate type of geological interest to the oil and gas industry. **Figure AA.1** shows the PSAC areas in Alberta. In discussing historical, current, and future oil and gas activity in Alberta, the AER often references such activity by PSAC area.

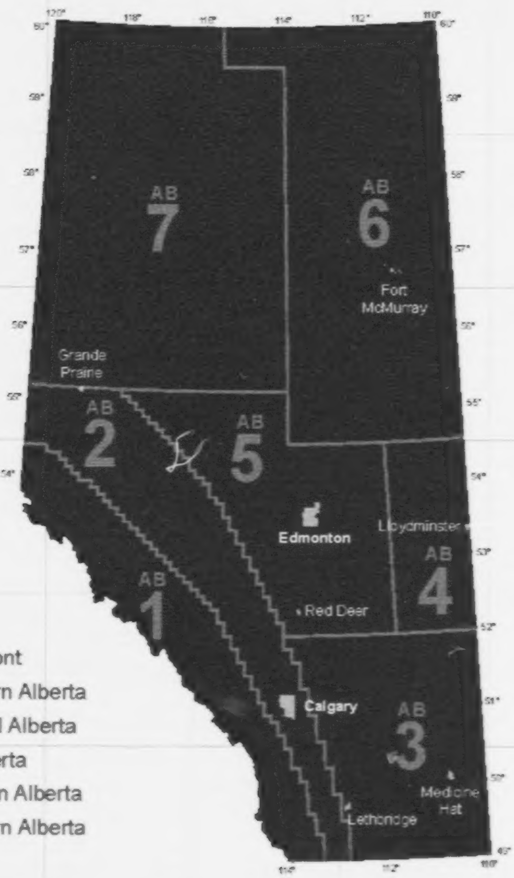


Figure AA.1
PSAC areas in Alberta

AB1 Foothills
AB2 Foothills Front
AB3 Southeastern Alberta
AB4 East Central Alberta
AB5 Central Alberta
AB6 Northeastern Alberta
AB7 Northwestern Alberta

Symbols

International System of Units (SI)

°C degree	Celsius	M	mega
d	day	m	metre
EJ	exajoule	MJ	megajoule
ha	hectare	mol	mole
J	joule	T	tera
kg	kilogram	t	tonne
kPa	kilopascal	TJ	terajoule

Imperial

bbl	barrel	°F degree	Fahrenheit
Btu	British thermal unit	psia	pounds per square inch absolute
cf	cubic foot	psig	pounds per square inch gauge
d	day	M	thousand
MM	million	B	billion
T	trillion		

Conversion Factors

Metric and Imperial Equivalent Units[a]

Metric	Imperial
1 m^3 of gas[b] (101.325 kPa and 15°C)	= 35.49373 cubic feet of gas
1 m^3 of ethane (equilibrium pressure and 15°C)	= 6.3301 Canadian barrels of ethane (equilibrium pressure and 60°F)
1 m^3 of propane (equilibrium pressure and 15°C)	= 6.3000 Canadian barrels of propane (equilibrium pressure and 60°F)
1 m^3 of butanes (equilibrium pressure and 15°C)	= 6.2968 Canadian barrels of butanes (equilibrium pressure and 60°F)
1 m^3 of oil or pentanes plus (equilibrium pressure and 15°C)	= 6.2929 Canadian barrels of oil or pentanes plus (equilibrium pressure and 60°F)
1 m^3 of water (equilibrium pressure and 15°C)	= 6.2901 Canadian barrels of water (equilibrium pressure and 60°F)
1 tonne	= 0.9842064 (U.K.) long tons (2240 pounds)
1 tonne	= 1.102311 short tons (2000 pounds)
1 kilojoule	= 0.9482133 British thermal units (Btu) as defined in the federal *Gas Inspection Act* (60-61°F)

[a] Reserves data in this report are presented in the International System of Units (SI). The provincial totals and a few other major totals are shown in both SI units and the imperial equivalents in the various tables.

[b] Volumes of gas are given as at a standard pressure and temperature of 101.325 kPa and 15°C respectively.

Value and Scientific Notation

Term	Value (short scale)	Scientific notation
kilo	thousand	10^3
mega	million	10^6
giga	billion	10^9
tera	thousand billion (trillion)	10^{12}
peta	million billion	10^{15}
exa	billion billion	10^{18}

Energy Content Factors

Energy resource	Gigajoules
Natural gas (per thousand cubic metres)	37.4[a]
Ethane (per cubic metre)	18.5
Propane (per cubic metre)	25.4
Butanes (per cubic metre)	28.2
Oil (per cubic metre)	
Light and medium crude oil	38.5
Heavy crude oil	41.4
Bitumen	42.8
Upgraded bitumen (synthetic crude oil)	39.4
Pentanes plus	33.1
Refined petroleum products (per cubic metre)	
Motor gasoline	34.7
Diesel	38.7
Aviation turbo fuel	35.9
Aviation gasoline	33.5
Kerosene	37.7
Light fuel oil	38.7
Heavy fuel oil	41.7
Naphthas	35.2
Lubricating oils and greases	39.2
Petrochemical feedstock	35.2
Asphalt	44.5
Coke	28.8
Other products (from refinery)	39.8
Coal (per tonne)	
Subbituminous	18.5
Bituminous	25.0
Electricity (per megawatt-hour of output)	3.6

[a] Based on the heating value at 1000 Btu/cf.

Appendix B Summary of Crude Bitumen, Conventional Crude Oil, Natural Gas Reserves, and Natural Gas Liquids

Table B.1 Initial in-place resources of crude bitumen by deposit

Oil Sands Area Oil sands deposit	Depth/region/zone (m)	Resource determination method	Initial volume in-place (10^6 m^3)
Athabasca			
Upper Grand Rapids	150–450+	Isopach	5 817
Middle Grand Rapids	150–450+	Isopach	2 171
Lower Grand Rapids	150–450+	Isopach	1 286
Wabiskaw-McMurray	0–750+	Isopach	152 432
Nisku	200–800+	Isopach	16 232
Grosmont	All zones	Isopach	64 537
Subtotal			**242 475**
Cold Lake			
Upper Grand Rapids	All zones	Isopach	5 377
Lower Grand Rapids	All zones	Isopach	10 004
Clearwater	350–625	Isopach	9 422
Wabiskaw-McMurray	Northern	Isopach	2 161
Wabiskaw-McMurray	Central-southern	Building block	1 439
Wabiskaw-McMurray	Cummings & McMurray	Isopach	687
Subtotal			**29 090**
Peace River			
Bluesky-Gething	300–800+	Isopach	10 968
Belloy	675–700	Building block	282
Upper Debolt	500–800	Building block	1 830
Lower Debolt	500–800	Building block	5 970
Shunda	500–800	Building block	2 510
Subtotal			**21 560**
Total			**293 125**

Table B.2 Basic data of crude bitumen deposits

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Athabasca								
Upper Grand Rapids								
150–450+	Isopach	5 817.00	359.00	8.5	0.092	0.58	0.33	0.42
Middle Grand Rapids								
150–450+	Isopach	2 171.00	183.00	6.8	0.084	0.55	0.32	0.45
Lower Grand Rapids								
150–450+	Isopach	1 286.00	134.00	5.6	0.083	0.52	0.33	0.48
Wabiskaw-McMurray								
0–65 (mineable)	Isopach	20 823.00	375.00	25.9	0.101	0.76	0.28	0.24
65–750+ (in situ)	Isopach	131 609.00	4 694.00	13.1	0.102	0.73	0.29	0.27
Nisku								
200–800+	Isopach	16 232.00	819.00	14.4	0.057	0.68	0.20	0.32
Grosmont								
D	Isopach	32 860.00	850.00	21.0	0.081	0.81	0.23	0.19
C	Isopach	18 755.00	1 069.00	13.6	0.054	0.78	0.17	0.22
B	Isopach	4 450.00	787.00	4.9	0.048	0.76	0.15	0.24
A	Isopach	8 472.00	1 274.00	6.5	0.041	0.72	0.14	0.28
Cold Lake								
Upper Grand Rapids								
All Zones	Total Isopach	5 377.00	612.00	4.8	0.090	0.65	0.28	0.35
Colony 1								
Lindbergh C	Isopach	0.18	0.05	1.5	0.115	0.79	0.31	0.21
Beaverdam A	Isopach	7.33	1.05	2.9	0.115	0.79	0.31	0.21
Beaverdam B	Isopach	4.75	0.52	3.5	0.122	0.84	0.31	0.16
Beaverdam C	Isopach	2.03	0.26	3.1	0.119	0.76	0.33	0.24
Beaverdam/ Bonnyville A	Isopach	12.11	1.90	2.6	0.116	0.80	0.31	0.20
Colony 2								
Frog Lake A	Isopach	2.01	0.47	1.8	0.109	0.75	0.31	0.25
Frog Lake B	Isopach	0.11	0.04	1.3	0.093	0.67	0.30	0.33
Frog Lake C	Isopach	0.35	0.12	1.3	0.103	0.74	0.30	0.26
Frog Lake D	Isopach	0.29	0.10	1.3	0.099	0.71	0.30	0.29
Frog Lake E	Isopach	0.43	0.13	1.4	0.106	0.79	0.29	0.21
Frog Lake F	Isopach	0.33	0.10	1.7	0.092	0.69	0.29	0.31

(continued on next page)

Table B.2 (*continued*)

Oil Sands Area / Oil sands deposit / Depth/region/zone / Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake M	Isopach	0.55	0.14	1.8	0.100	0.72	0.30	0.28
Frog Lake N	Isopach	0.80	0.25	1.5	0.099	0.71	0.30	0.29
Frog Lake O	Isopach	0.15	0.03	2.5	0.096	0.66	0.31	0.34
Lindbergh A	Isopach	0.83	0.26	1.6	0.091	0.68	0.29	0.32
Lindbergh D	Isopach	1.20	0.13	3.4	0.130	0.86	0.32	0.14
Lindbergh E	Isopach	6.11	0.39	5.3	0.139	0.92	0.32	0.08
Lindbergh F	Isopach	0.85	0.09	3.3	0.136	0.90	0.32	0.10
Lindbergh G	Isopach	2.35	0.33	2.7	0.124	0.82	0.32	0.18
Lindbergh J	Isopach	3.56	0.60	2.6	0.106	0.76	0.30	0.24
Lindbergh K	Isopach	6.23	0.92	3.0	0.107	0.74	0.31	0.26
Lindbergh L	Isopach	1.99	0.31	2.4	0.125	0.83	0.32	0.17
Colony 3								
Frog Lake G	Isopach	0.48	0.09	2.1	0.116	0.83	0.30	0.17
Frog Lake H	Isopach	0.15	0.06	1.2	0.096	0.69	0.30	0.31
Frog Lake I	Isopach	1.61	0.23	2.9	0.111	0.80	0.30	0.20
Frog Lake J	Isopach	1.03	0.20	2.2	0.112	0.74	0.32	0.26
Frog Lake L	Isopach	130.95	6.43	7.4	0.130	0.86	0.32	0.14
Frog Lake P	Isopach	0.70	0.15	2.3	0.092	0.69	0.29	0.31
Lindbergh H	Isopach	2.04	0.24	3.2	0.124	0.82	0.32	0.18
Lindbergh I	Isopach	0.15	0.02	2.9	0.121	0.80	0.32	0.20
Colony Channel								
St. Paul A	Isopach	6.41	0.68	3.2	0.140	0.89	0.33	0.11
Grand Rapids 2								
Beaverdam A	Isopach	3.86	0.70	2.3	0.112	0.74	0.32	0.26
Beaverdam B	Isopach	1.96	0.39	2.5	0.094	0.70	0.29	0.30
Beaverdam D	Isopach	1.12	0.25	2.0	0.103	0.71	0.31	0.29
Beaverdam E	Isopach	0.23	0.11	0.9	0.111	0.71	0.33	0.29
Beaverdam G	Isopach	1.41	0.30	1.9	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	9.97	1.34	3.0	0.118	0.78	0.32	0.22
Beaverdam I	Isopach	0.40	0.11	1.4	0.130	0.77	0.35	0.23
Frog Lake/ Beaverdam A	Isopach	64.45	6.69	3.7	0.125	0.77	0.34	0.23
Beaverdam/ Bonnyville A	Isopach	2.59	0.53	2.1	0.112	0.74	0.32	0.26

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Table B.2 *(continued)*

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Grand Rapids Channel								
Wolf Lake A	Isopach	14.90	0.35	14.8	0.140	0.80	0.36	0.20
Waseca								
Frog Lake A	Isopach	1.09	0.38	1.7	0.076	0.57	0.29	0.43
Frog Lake B	Isopach	77.34	4.65	6.8	0.116	0.77	0.32	0.23
Beaverdam A	Isopach	4.59	0.21	8.6	0.121	0.77	0.33	0.23
Beaverdam B	Isopach	9.72	0.30	10.7	0.145	0.89	0.34	0.11
Beaverdam C	Isopach	6.57	0.15	15.0	0.140	0.86	0.34	0.14
Frog Lake/Lindbergh A	Isopach	135.86	15.56	4.3	0.095	0.68	0.30	0.32
Lower Grand Rapids								
All Zones	Total Isopach	1 004.00	658.00	7.8	0.092	0.65	0.30	0.35
Sparky								
Frog Lake A	Isopach	4.60	0.75	2.9	0.100	0.69	0.31	0.31
Frog Lake B	Isopach	0.30	0.06	2.2	0.109	0.72	0.32	0.28
Frog Lake C	Isopach	0.79	0.16	2.2	0.107	0.74	0.31	0.26
Frog Lake D	Isopach	0.21	0.07	1.7	0.083	0.62	0.29	0.38
Frog Lake E	Isopach	1.54	0.31	2.6	0.087	0.65	0.29	0.35
Frog Lake F	Isopach	12.36	1.47	3.1	0.130	0.83	0.33	0.17
Frog Lake G	Isopach	0.51	0.06	3.2	0.123	0.85	0.31	0.15
Frog Lake H	Isopach	0.09	0.02	1.7	0.127	0.81	0.33	0.19
Frog Lake I	Isopach	5.72	0.74	2.6	0.144	0.85	0.35	0.15
Lindbergh A	Isopach	54.96	8.17	3.1	0.102	0.70	0.31	0.30
Lindbergh C	Isopach	0.91	0.37	1.4	0.084	0.60	0.30	0.40
Lindbergh D	Isopach	26.51	4.05	2.7	0.116	0.74	0.33	0.26
Lindbergh E	Isopach	0.12	0.09	0.8	0.078	0.67	0.26	0.33
Lindbergh F	Isopach	0.31	0.14	1.3	0.081	0.58	0.30	0.42
Lindbergh I	Isopach	0.13	0.07	0.9	0.100	0.64	0.33	0.36
Lindbergh K	Isopach	0.84	0.24	1.7	0.093	0.67	0.30	0.33
Lindbergh L	Isopach	3.45	0.58	2.1	0.140	0.83	0.34	0.17
Lindbergh M	Isopach	7.10	0.85	3.1	0.130	0.83	0.33	0.17
Beaverdam A	Isopach	3.90	0.30	5.2	0.119	0.73	0.34	0.27
Beaverdam B	Isopach	3.40	0.33	4.8	0.103	0.63	0.34	0.37
Beaverdam C	Isopach	6.53	0.79	3.0	0.130	0.80	0.34	0.20

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Table B.2 *(continued)*

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Beaverdam D	Isopach	30.23	3.48	3.3	0.124	0.82	0.32	0.18
Beaverdam E	Isopach	27.25	3.41	3.0	0.127	0.81	0.33	0.19
Beaverdam F	Isopach	8.07	1.17	2.6	0.129	0.82	0.33	0.18
Beaverdam H	Isopach	1.68	0.21	2.9	0.133	0.79	0.35	0.21
Cold Lake A	Isopach	9.74	1.00	3.7	0.128	0.76	0.35	0.24
Cold Lake B	Isopach	1.77	0.27	2.4	0.135	0.77	0.36	0.23
Mann Lake/ Seibert Lk A	Isopach	6.61	0.55	4.4	0.129	0.82	0.33	0.18
Lower Grand Rapids 2								
Frog Lake OO	Isopach	1.71	0.27	2.9	0.103	0.74	0.30	0.26
Frog Lake QQ	Isopach	0.55	0.10	2.2	0.119	0.82	0.31	0.18
Lindbergh G	Isopach	35.32	5.94	2.8	0.100	0.69	0.31	0.31
Lindbergh K	Isopach	0.76	0.21	2.0	0.084	0.63	0.29	0.37
Lindbergh VV	Isopach	0.36	0.12	1.5	0.095	0.68	0.30	0.32
Lindbergh WW	Isopach	2.60	0.51	2.0	0.122	0.78	0.33	0.22
Beaverdam A	Isopach	4.66	1.67	1.8	0.069	0.62	0.25	0.38
Cold Lake A	Isopach	3.09	0.89	1.5	0.111	0.71	0.33	0.29
Cold Lake D	Isopach	0.58	0.19	1.2	0.122	0.75	0.34	0.25
Lower Grand Rapids 3								
Frog Lake C	Isopach	4.80	0.46	4.4	0.112	0.77	0.31	0.23
Frog Lake D	Isopach	10.38	1.09	3.7	0.121	0.80	0.32	0.20
Frog Lake E	Isopach	4.50	0.88	2.3	0.106	0.73	0.31	0.27
Frog Lake F	Isopach	0.41	0.10	1.9	0.098	0.73	0.29	0.27
Lindbergh F	Isopach	31.58	3.02	4.2	0.118	0.78	0.32	0.22
Lindbergh L	Isopach	1.58	0.24	2.9	0.108	0.69	0.33	0.31
Lindbergh M	Isopach	8.40	1.46	2.7	0.100	0.69	0.31	0.31
Lindbergh O	Isopach	11.50	1.54	3.7	0.095	0.68	0.30	0.32
Lindbergh P	Isopach	2.04	0.25	3.5	0.110	0.76	0.31	0.24
Lindbergh Q	Isopach	27.61	2.92	3.7	0.119	0.79	0.32	0.21
Lindbergh S	Isopach	2.46	0.37	2.8	0.113	0.72	0.33	0.28
Lindbergh T	Isopach	2.97	0.47	2.6	0.115	0.76	0.32	0.24
Lindbergh U	Isopach	0.18	0.06	1.4	0.094	0.70	0.29	0.30
Lindbergh V	Isopach	0.13	0.06	1.3	0.081	0.56	0.31	0.44
Lindbergh X	Isopach	0.75	0.20	2.4	0.073	0.57	0.28	0.43

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Table B.2 *(continued)*

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Lindbergh Y	Isopach	1.61	0.35	2.5	0.086	0.59	0.31	0.41
Lindbergh Z	Isopach	0.12	0.07	0.8	0.094	0.65	0.31	0.35
Lindbergh AA	Isopach	3.26	0.50	3.1	0.099	0.71	0.30	0.29
Lindbergh BB	Isopach	0.08	0.03	1.4	0.093	0.59	0.33	0.41
Lindbergh CC	Isopach	2.18	0.31	3.0	0.110	0.76	0.31	0.24
Lindbergh OO	Isopach	0.24	0.09	1.6	0.075	0.54	0.30	0.46
Lindbergh XX	Isopach	0.32	0.09	1.9	0.086	0.62	0.30	0.38
Lindbergh YY	Isopach	3.94	0.39	4.0	0.117	0.81	0.31	0.19
Frog Lake/ Lindbergh C	Isopach	9.95	1.07	3.7	0.119	0.79	0.32	0.21
Frog Lake/ Beaverdam A	Isopach	3.85	0.55	2.8	0.119	0.73	0.34	0.27
Lindbergh/ St. Paul A	Isopach	9.58	0.81	4.6	0.121	0.80	0.32	0.20
Beaverdam B	Isopach	84.40	9.49	3.5	0.121	0.77	0.33	0.23
Beaverdam G	Isopach	1.46	0.25	2.4	0.115	0.76	0.32	0.24
Beaverdam H	Isopach	1.65	0.31	2.1	0.120	0.74	0.34	0.26
Cold Lake B	Isopach	2.73	0.56	2.0	0.116	0.71	0.34	0.29
Wolf Lake D	Isopach	23.34	2.64	3.1	0.139	0.82	0.35	0.18
Lower Grd Rap Channel Sd								
Beaverdam F	Isopach	26.72	0.86	10.4	0.145	0.83	0.36	0.17
Wolf Lake F	Isopach	101.14	3.39	10.3	0.140	0.83	0.35	0.17
Lower Grand Rapids 4								
Frog Lake G	Isopach	9.15	0.97	3.6	0.124	0.79	0.33	0.21
Frog Lake I	Isopach	15.37	1.52	4.0	0.121	0.80	0.32	0.20
Frog Lake J	Isopach	1.49	0.21	2.8	0.118	0.78	0.32	0.22
Frog Lake K	Isopach	0.80	0.06	4.3	0.146	0.93	0.33	0.07
Frog Lake L	Isopach	0.60	0.11	2.1	0.121	0.80	0.32	0.20
Frog Lake M	Isopach	1.04	0.21	2.2	0.107	0.71	0.32	0.29
Frog Lake N	Isopach	2.88	0.34	3.1	0.129	0.82	0.33	0.18
Frog Lake P	Isopach	1.97	0.22	3.2	0.135	0.86	0.33	0.14
Frog Lake Q	Isopach	1.43	0.25	2.6	0.102	0.73	0.30	0.27
Frog Lake T	Isopach	0.25	0.06	1.7	0.122	0.78	0.33	0.22
Frog Lake NN	Isopach	5.41	0.42	5.8	0.104	0.72	0.31	0.28
Frog Lake PP	Isopach	0.13	0.03	2.4	0.086	0.57	0.32	0.43

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Lindbergh B	Isopach	17.65	1.97	3.5	0.121	0.80	0.32	0.20
Lindbergh C	Isopach	6.85	0.93	3.1	0.113	0.75	0.32	0.25
Lindbergh D	Isopach	3.29	0.45	3.1	0.102	0.76	0.31	0.24
Lindbergh E	Isopach	3.24	0.50	2.7	0.115	0.79	0.31	0.21
Lindbergh H	Isopach	1.95	0.33	2.5	0.109	0.75	0.31	0.25
Lindbergh I	Isopach	1.44	0.25	2.5	0.109	0.75	0.31	0.25
Lindbergh J	Isopach	3.54	0.56	2.7	0.110	0.76	0.31	0.24
Lindbergh DD	Isopach	0.31	0.08	2.0	0.092	0.61	0.32	0.39
Lindbergh EE	Isopach	0.05	0.10	2.2	0.009	0.73	0.03	0.27
Lindbergh FF	Isopach	1.50	0.26	2.4	0.115	0.76	0.32	0.24
Lindbergh GG	Isopach	0.19	0.04	2.3	0.098	0.60	0.34	0.40
Lindbergh HH	Isopach	0.80	0.17	2.4	0.090	0.62	0.31	0.38
Lindbergh II	Isopach	0.20	0.04	2.6	0.089	0.59	0.32	0.41
Lindbergh JJ	Isopach	6.99	0.83	3.3	0.119	0.79	0.32	0.21
Lindbergh KK	Isopach	0.63	0.13	2.2	0.105	0.67	0.33	0.33
Lindbergh MM	Isopach	10.79	1.30	3.4	0.116	0.77	0.32	0.23
Lindbergh NN	Isopach	2.73	0.38	2.9	0.119	0.76	0.33	0.24
Lindbergh PP	Isopach	2.67	0.34	3.7	0.099	0.71	0.30	0.29
Lindbergh QQ	Isopach	0.79	0.14	2.4	0.107	0.80	0.29	0.20
Lindbergh RR	Isopach	0.05	0.02	1.4	0.089	0.64	0.30	0.36
Lindbergh SS	Isopach	3.12	0.29	4.7	0.110	0.70	0.33	0.30
Lindbergh UU	Isopach	0.57	0.10	2.4	0.113	0.75	0.32	0.25
Lindbergh ZZ	Isopach	10.13	1.10	3.8	0.113	0.78	0.31	0.22
Lindbergh EEE	Isopach	0.56	0.05	4.2	0.129	0.82	0.33	0.18
Lindbergh FFF	Isopach	3.81	0.54	2.7	0.127	0.80	0.33	0.20
Lindbergh GGG	Isopach	1.42	0.22	2.4	0.129	0.81	0.33	0.19
Lindbergh HHH	Isopach	2.21	0.27	3.0	0.129	0.82	0.33	0.18
Lindbergh JJJ	Isopach	2.20	0.27	3.0	0.127	0.84	0.32	0.16
Beaverdam C	Isopach	24.01	2.69	3.5	0.119	0.79	0.32	0.21
Cold Lake C	Isopach	4.22	0.77	2.2	0.117	0.72	0.34	0.28
Lindbergh/ St. Paul B	Isopach	9.63	1.22	3.4	0.110	0.73	0.32	0.27
Lower Grand Rapids 5								

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Table B.2 (*continued*)

Oil Sands Area Oil sands deposit Depth/region/zone Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Lindbergh AAA	Isopach	2.51	0.40	3.1	0.093	0.70	0.29	0.30
Lindbergh BBB	Isopach	0.29	0.10	1.6	0.083	0.62	0.29	0.38
Lindbergh CCC	Isopach	0.11	0.04	1.6	0.080	0.60	0.29	0.40
St. Paul A	Isopach	1.93	0.32	3.1	0.089	0.64	0.30	0.36
St. Paul B	Isopach	0.24	0.06	2.2	0.084	0.63	0.29	0.37
Lloydminster								
Frog Lake A	Isopach	1.34	0.17	3.9	0.097	0.62	0.33	0.38
Frog Lake B	Isopach	4.63	0.54	4.4	0.091	0.63	0.31	0.37
Frog Lake C	Isopach	2.85	0.38	3.6	0.100	0.64	0.33	0.36
Lindbergh D	Isopach	3.65	0.54	2.8	0.116	0.74	0.33	0.26
Lindbergh F	Isopach	2.91	0.48	3.6	0.078	0.56	0.30	0.44
Lindbergh G	Isopach	1.01	0.14	4.0	0.085	0.61	0.30	0.39
Lindbergh H	Isopach	28.27	2.31	5.1	0.113	0.75	0.32	0.25
Lindbergh I	Isopach	7.66	0.52	5.6	0.123	0.85	0.31	0.15
Lindbergh J	Isopach	0.68	0.21	1.4	0.109	0.72	0.32	0.28
Beaverdam A	Isopach	128.78	6.39	8.9	0.107	0.71	0.32	0.29
Frog Lake/ Lindbergh A	Isopach	5.31	0.59	4.6	0.091	0.63	0.31	0.37
Lindbergh/ St. Paul B	Isopach	60.39	2.43	8.9	0.133	0.85	0.33	0.15
Lindbergh/ St. Paul C	Isopach	3.81	0.34	4.7	0.113	0.75	0.32	0.25
Lindbergh/ Beaverdam A	Isopach	44.56	3.16	5.5	0.120	0.83	0.31	0.17
Lind./Beaver./ Bonny. A	Isopach	511.25	19.81	8.9	0.138	0.85	0.34	0.15
Cold Lake A	Isopach	15.74	1.29	4.7	0.125	0.74	0.35	0.26
Clearwater								
350–625	Isopach	9 422.00	433.00	11.8	0.089	0.59	0.31	0.41
Wabiskaw-McMurray								
Northern	Isopach	2 161.00	132.00	8.9	0.087	0.64	0.29	0.36
Central-Southern	Building Block	1 439.00	285.00	4.1	0.057	0.51	0.25	0.49
Cummings 1								
Frog Lake A	Isopach	4.07	0.69	2.4	0.116	0.83	0.30	0.17
Frog Lake B	Isopach	1.52	0.17	3.4	0.124	0.82	0.32	0.18
Frog Lake C	Isopach	5.20	0.66	3.0	0.122	0.81	0.32	0.19

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Table B.2 (*continued*)

Oil Sands Area / Oil sands deposit / Depth/region/zone / Sector-pool	Resource determination method	Initial volume in-place (10^6 m^3)	Area (10^3 ha)	Average pay thickness (m)	Bitumen saturation mass (fraction)	Bitumen saturation pore volume (fraction)	Porosity (fraction)	Water saturation (fraction)
Frog Lake/ Lindbergh A	Isopach	38.28	3.76	3.9	0.122	0.84	0.31	0.16
Lindbergh/ St. Paul A	Isopach	273.08	29.62	3.9	0.109	0.78	0.30	0.22
Cummings 2								
St. Paul B	Isopach	1.32	0.18	3.2	0.106	0.76	0.30	0.24
Lindbergh/ St. Paul B	Isopach	221.36	20.89	4.2	0.117	0.81	0.31	0.19
McMurray								
Lindbergh A	Isopach	89.87	5.49	6.1	0.127	0.84	0.32	0.16
Lindbergh B	Isopach	0.09	0.02	2.4	0.083	0.68	0.27	0.32
Lindbergh C	Isopach	42.72	5.83	3.1	0.112	0.77	0.31	0.23
Lindbergh D	Isopach	0.94	0.11	3.2	0.125	0.86	0.31	0.14
Lindbergh E	Isopach	0.07	0.05	0.7	0.088	0.69	0.28	0.31
Lindbergh F	Isopach	8.11	0.55	6.7	0.103	0.71	0.31	0.29
St. Paul A	Isopach	0.04	0.02	1.2	0.090	0.62	0.31	0.38
Peace River								
Bluesky-Gething								
300–800+	Isopach	10 968.00	1 016.00	6.1	0.081	0.68	0.26	0.32
Belloy								
675–700	Building Block	282.00	26.00	8.0	0.078	0.64	0.27	0.36
Upper Debolt								
500–800	Building Block	1 830.00	100.00	13.0	0.050	0.61	0.19	0.39
Lower Debolt								
500–800	Building Block	5 970.00	202.00	29.0	0.051	0.67	0.18	0.33
Shunda								
500–800	Building Block	2 510.00	143.00	14.0	0.053	0.52	0.23	0.48
Total		**293 124.67**						

Table B.3 Conventional crude oil reserves as of each year-end (10^6 m^3)

Year	Changes to initial established reserves: New discoveries	EOR additions	Development	Revisions	Net changes	Initial established reserves	Cumulative production	Remaining established reserves
1968	62.0				119.8	1 643.1	430.3	1 212.8
1969	40.5				54.5	1 697.5	474.7	1 222.8
1970	8.4				36.7	1 734.4	526.5	1 207.9
1971	14.0				22.1	1 756.5	582.9	1 173.6
1972	10.8				20.0	1 776.0	650.0	1 126.0
1973	5.1				9.2	1 785.7	733.7	1 052.0
1974	4.3				38.5	1 824.2	812.7	1 011.5
1975	1.6				7.0	1 831.1	880.2	950.9
1976	2.5				-18.6	1 812.5	941.2	871.3
1977	4.8				19.1	1 831.6	1 001.6	830.0
1978	24.9				24.4	1 856.1	1 061.6	794.5
1979	19.2				34.3	1 890.3	1 130.1	760.2
1980	9.0				22.8	1 913.2	1 193.3	719.9
1981	15.0	7.2			32.6	1 945.8	1 249.8	696.0
1982	16.8	6.6			6.9	1 952.8	1 303.4	649.4
1983	21.4	17.9			64.1	2 016.8	1 359.0	657.8
1984	29.1	24.1			42.0	2 058.9	1 418.2	640.7
1985	32.7	21.6			64.0	2 123.0	1 474.5	648.5
1986	28.6	24.6	16.6	-30.7	39.1	2 162.4	1 527.7	634.7
1987	20.9	10.5	12.8	-11.2	33.0	2 195.4	1 581.6	613.8
1988	18.0	16.5	18.0	-15.8	36.7	2 231.7	1 638.8	592.9
1989	17.0	7.8	12.9	-16.3	21.4	2 253.1	1 692.6	560.5
1990	13.0	8.4	7.2	-25.6	3.0	2 256.1	1 745.7	510.4
1991	10.2	9.1	10.6	-20.5	9.4	2 265.6	1 797.1	468.5
1992	9.0	2.8	12.3	3.0	27.1	2 292.7	1 850.7	442.0
1993	7.3	7.9	14.2	9.8	39.2	2 331.9	1 905.1	426.8
1994	10.5	5.7	11.1	-22.6	4.7	2 336.5	1 961.7	374.8
1995	10.2	9.2	20.8	14.8	55.0	2 391.6	2 017.5	374.1
1996	9.7	6.1	16.3	-9.5	22.6	2 414.1	2 072.3	341.8
1997	8.5	4.2	16.1	8.7	37.5	2 451.6	2 124.8	326.8
1998	8.9	2.9	17.5	9.2	38.5	2 490.1	2 174.9	315.2
1999	5.6	2.1	7.2	16.6	31.5	2 521.5	2 219.9	301.6
2000	7.8	1.5	13.4	10.0	32.8	2 554.3	2 262.9	291.4
2001	9.1	0.8	13.6	5.2	28.6	2 583.0	2 304.7	278.3

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Table B.3 (*continued*)

Year	Changes to initial established reserves					Initial established reserves	Cumulative production	Remaining established reserves
	New discoveries	EOR additions	Development	Revisions	Net changes			
2002	7.0	0.6	8.1	4.6	20.2	2 603.3	2 343.0	260.3
2003	6.9	1.0	5.9	17.1	30.8	2 634.0	2 380.1	253.9
2004	6.1	3.2	8.0	13.6	30.9	2 664.9	2 415.7	249.2
2005	5.5	1.2	13.2	18.9	38.8	2 703.7	2 448.9	254.8
2006	8.2	1.9	14.8	2.2	27.1	2 730.8	2 480.7	250.1
2007	6.8	2.2	11.8	-0.2	20.6	2 751.6	2 510.9	240.7
2008	6.9	6.2	9.3	-0.7	21.7	2 773.1	2 540.1	233.0
2009	4.0	4.8	7.4	+5.8	21.8	2 794.9	2 566.5	228.4
2010	3.8	5.8	23.5	+1.7	34.8	2 829.7	2 592.8	236.9
2011	4.0	6.4	14.0	+9.0	33.5	2 863.2	2 617.3	245.9
2012	5.8	2.2	52.9	-2.4	58.5	2 921.7	2 652.5	269.2
2013	4.9	2.2	30.8	+10.1	50.0	2 970.0	2 687.0	283.4

Table B.4 Summary of marketable natural gas reserves as of each year-end (10^9 m^3)

Year	Changes to initial established reserves: New discoveries	Development	Revisions	Net changes	Initial established reserves	Cumulative production	Remaining established reserves[a]	Remaining reserves at 37.4 MJ/m³
1966				40.7	1 251.0	178.3	1 072.6	1 142.5
1967				73.9	1 324.9	205.8	1 119.1	1 189.6
1968				134.6	1 459.5	235.8	1 223.6	1 289.0
1969				87.5	1 547.0	273.6	1 273.4	1 342.6
1970				46.2	1 593.2	313.8	1 279.4	1 352.0
1971				45.4	1 638.6	362.3	1 276.3	1 346.9
1972				45.2	1 683.9	414.7	1 269.1	1 337.6
1973				183.4	1 867.2	470.7	1 396.6	1 464.5
1974				147.0	2 014.3	527.8	1 486.5	1 550.2
1975				20.8	2 035.1	584.3	1 450.8	1 512.8
1976				105.6	2 140.7	639.0	1 501.7	1 563.9
1977				127.6	2 268.2	700.0	1 568.3	1 630.3
1978				163.3	2 431.6	766.3	1 665.2	1 730.9
1979				123.2	2 554.7	836.4	1 718.4	1 786.2
1980				94.2	2 647.1	900.2	1 747.0	1 812.1
1981				117.0	2 764.1	968.8	1 795.3	1 864.8
1982				118.7	2 882.8	1 029.7	1 853.1	1 924.6
1983				39.0	2 921.8	1 095.6	1 826.2	1 898.7
1984				40.5	2 962.3	1 163.9	1 798.4	1 872.2
1985				42.6	3 004.9	1 236.7	1 768.3	1 840.0
1986				21.8	3 026.7	1 306.6	1 720.1	1 790.3
1987				0.0	3 026.7	1 375.0	1 651.7	1 713.7
1988				64.6	3 091.3	1 463.5	1 627.7	1 673.7
1989				107.8	3 199.0	1 549.3	1 648.7	1 689.2
1990				87.8	3 286.8	1 639.4	1 647.4	1 694.2
1991				57.6	3 344.4	1 718.2	1 626.2	1 669.7
1992				72.5	3 416.9	1 822.1	1 594.7	1 637.6
1993				58.6	3 475.5	1 940.5	1 534.9	1 573.7
1994				74.2	3 549.7	2 059.3	1 490.3	1 526.3
1995				123.0	3 672.7	2 183.9	1 488.8	1 521.8
1996				10.9	3 683.5	2 305.5	1 378.1	1 410.1
1997				33.1	3 716.6	2 432.7	1 283.9	1 314.4
1998				93.0	3 809.6	2 569.8	1 239.9	1 269.3
1999	38.5	40.5	30.7	109.7	3 919.3	2 712.1	1 207.2	1 228.7

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Table B.4 (*continued*)

Year	Changes to initial established reserves: New discoveries	Development	Revisions	Net changes	Initial established reserves	Cumulative production	Remaining established reserves[a]	Remaining reserves at 37.4 MJ/m³
2000	50.3	76.5	17.5	144.3	4 063.5	2 852.8	1 210.7	1 221.1
2001	62.5	32.4	21.5	116.4	4 179.9	2 995.5	1 184.4	1 276.8
2002	83.4	60.4	-10.2	133.6	4 313.5	3 142.1	1 171.4	1 258.0
2003	89.4	53.8	-56.0	87.2	4 400.7	3 278.6	1 122.2	1 166.7
2004	55.5	64.5	25.9	145.9	4 546.6	3 419.6	1 127.0	1 172.3
2005	40.4	49.9	35.0	125.7	4 672.4	3 552.4	1 120.0	1 164.0
2006	83.4	48.4	-5.4	126.3	4 798.7	3 683.5	1 115.2	1 136.3
2007	71.0	30.0	-6.4	94.6	4 893.3	3 823.9	1 069.3	1 112.2
2008	69.3	31.3	54.8	155.4	5 048.7	3 950.5	1 098.2	1 142.3
2009	43.1	20.1	18.8	82.0	5 130.7	4 075.0	1 055.7	1 098.0
2010	24.3	25.3	33.2	82.8	5 213.5	4 188.4	1 025.1	1 065.7
2011	20.8	24.0	24.7	69.5	5 283.1	4 338.0	945.1	987.0
2012	16.2	8.0	33.8	58.0	5 341.1	4 425.4	915.7	957.2
2013	20.9	12.4	46.2	79.5	5 420.6	4 523.0	897.5	941.0

[a] At field plant.

Table B.5 Natural gas reserves of multifield pools as of December 31, 2013

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
MFP8515 Banff	
Haro MFP8515 Banff	79
Rainbow MFP8515 Banff	5
Rainbow South MFP8515 Banff	67
Total	151
MFP8516 Viking	
Fenn West MFP8516 Viking	5
Fenn-Big Valley MFP8516 Viking	1
Total	6
MFP8524 Halfway	
Valhalla MFP8524 Halfway	2 098
Wembley MFP8524 Halfway	1 895
Total	3 993
MFP8525 Colony	
Ukalta MFP8525 Colony	0
Whitford MFP8525 Colony	0
Total	0
MFP8528 Bluesky	
Rainbow MFP8528 Bluesky	136
Sousa MFP8528 Bluesky	495
Total	631
MFP8541 Second White Specks	
Cherry MFP8541 2WS	11
Granlea MFP8541 2WS	24
Taber MFP8541 2WS	103
Total	138
Commingled MFP9502	
Ansell Commingled MFP9502	13 427
Edson Commingled MFP9502	1 693
Medicine Lodge Commingled MFP9502	1 187
Minehead Commingled MFP9502	1 766
Nosehill MFP8507	115
Sundance Commingled MFP9502	8 100
Wild River Commingled MFP9502	302
Total	26 590
Commingled MFP9503	
Hairy Hill Commingled MFP9503	200
Willingdon Commingled MFP9503	9
Total	209
Commingled MFP9504	
Alix Commingled MFP9504	351
Bashaw Commingled MFP9504	1 788
Buffalo Lake Commingled MFP9504	5
Chigwell Commingled MFP9504	81
Chigwell North Commingled MFP9504	197
Clive Commingled MFP9504	377
Donalda Commingled MFP9504	86
Dorenlee Commingled MFP9504	2
Ferintosh Commingled MFP9504	3
Haynes Commingled MFP9504	64
Lacombe Commingled MFP9504	6
Malmo Commingled MFP9504	333
Nevis Commingled MFP9504	1 281
Wood River Commingled MFP9504	108
Total	4 682
Commingled MFP9505	
Bigoray Commingled MFP9505	158
Pembina Commingled MFP9505	684
Total	842
Commingled MFP9506	
Bonnie Glen Commingled MFP9506	23
Ferrybank Commingled MFP9506	152
Total	175
Commingled MFP9508	
Fairydell-Bon Accord Commingled MFP9508	62
Peavey Commingled MFP9508	1
Redwater Commingled MFP9508	1 365
Total	1 428
Commingled MFP9509	
Albers Commingled MFP9509	4
Beaverhill Lake Commingled MFP9509	416
Bellshill Lake Commingled MFP9509	28
Birch Commingled MFP9509	5
Bruce Commingled MFP9509	614
Dinant Commingled MFP9509	0
Edberg Commingled MFP9509	0
Fort Saskatchewan Commingled MFP9509	41
Holmberg Commingled MFP9509	254
Kelsey Commingled MFP9509	111
Killam Commingled MFP9509	212
Killam North Commingled MFP9509	56
Mannville Commingled MFP9509	236
Sedgewick Commingled MFP9509	4
Viking-Kinsella Commingled MFP9509	1 201
Wainwright Commingled MFP9509	312
Total	3 494
Commingled MFP9510	
Chickadee Commingled MFP9510	2 129
Fox Creek Commingled MFP9510	784

(continued on next page)

Table B.5 *(continued)*

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Kaybob South Commingled MFP9510	235
Windfall Commingled MFP9510	0
Total	3 148
Commingled MFP9511	
Hudson Commingled MFP9511	31
Sedalia Commingled MFP9511	144
Total	175
Commingled MFP9512	
Inland Commingled MFP9512	13
Royal Commingled MFP9512	0
Total	13
Commingled MFP9513	
Elmworth Commingled MFP9513	15 212
Sinclair Commingled MFP9513	4 058
Total	19 270
Commingled MFP9514	
Connorsville Commingled MFP9514	555
Wintering Hills Commingled MFP9514	68
Total	623
Commingled MFP9515	
Craigmyle Commingled MFP9515	2
Dowling Lake Commingled MFP9515	5
Garden Plains Commingled MFP9515	673
Hanna Commingled MFP9515	446
Provost Commingled MFP9515	3 151
Racosta Commingled MFP9515	65
Richdale Commingled MFP9515	66
Stanmore Commingled MFP9515	24
Sullivan Lake Commingled MFP9515	42
Watts Commingled MFP9515	37
Total	4 511
Commingled MFP9516	
Knopcik Commingled MFP9516	594
Valhalla Commingled MFP9516	23
Total	617
Commingled MFP9517	
Comrey Commingled MFP9517	13
Conrad Commingled MFP9517	84
Forty Mile Commingled MFP9517	42
Pendant D'Oreille Commingled MFP9517	808
Smith Coulee Commingled MFP9517	272
Total	1 219
Commingled MFP9520	
Gadsby Commingled MFP9520	2
Leahurst Commingled MFP9520	36
Total	38

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Commingled MFP9522	
Enchant Commingled MFP9522	192
Grand Forks Commingled MFP9522	5
Little Bow Commingled MFP9522	2
Retlaw Commingled MFP9522	271
Vauxhall Commingled MFP9522	14
Total	484
Commingled MFP9524	
Stirling Commingled MFP9524	80
Warner Commingled MFP9524	11
Total	91
Commingled MFP9525	
Resthaven Commingled MFP9525	2 351
Smoky Commingled MFP9525	697
Total	3 048
Commingled MFP9526	
Garrington Commingled MFP9526	43
Innisfail Commingled MFP9526	15
Markerville Commingled MFP9526	169
Medicine River Commingled MFP9526	159
Penhold Commingled MFP9526	3
Sylvan Lake Commingled MFP9526	590
Tindastoll Commingled MFP9526	39
Total	1 018
Commingled MFP9527	
Crystal Commingled MFP9527	25
Gilby Commingled MFP9527	32
Minnehik-Buck Lake Commingled MFP9527	158
Westerose South Commingled MFP9527	200
Wilson Creek Commingled MFP9527	230
Total	645
Commingled MFP9529	
Berland River Commingled MFP9529	24
Berland River West Commingled MFP9529	55
Elmworth Commingled MFP9529	406
Fir Commingled MFP9529	10 034
Kaybob South Commingled MFP9529	7 258
Red Rock Commingled MFP9529	3 604
Sundance Commingled MFP9529	9 290
Wapiti Commingled MFP9529	29 492
Wild River Commingled MFP9529	17 228
Wildhay Commingled MFP9529	572
Total	77 963

(continued on next page)

Table B.5 (*continued*)

Multifield pool Field and pool	Remaining established reserves (10^6 m^3)
Commingled MFP9530	
Gilby Commingled MFP9530	37
Prevo Commingled MFP9530	29
Total	66
Commingled MFP9531	
Nosehill Commingled MFP9531	1 110
Pine Creek Commingled MFP9531	1 345
Sundance Commingled MFP9531	14
Total	2 469
Commingled MFP9532	
Grizzly Commingled MFP9532	125
Waskahigan Commingled MFP9532	37
Total	162
Commingled MFP9533	
Bigstone Commingled MFP9533	125
Placid Commingled MFP9533	844
Total	969
Commingled MFP9534	
Jenner Commingled MFP9534	2
Princess Commingled MFP9534	0
Total	2
Commingled MFP9536	
Chinook Commingled MFP9536	109
Dobson Commingled MFP9536	7
Heathdale Commingled MFP9536	18
Kirkwall Commingled MFP9536	9
Sedalia Commingled MFP9536	2
Sounding Commingled MFP9536	68
Stanmore Commingled MFP9536	58
Total	271
Commingled MFP9537	
Ferrier Commingled MFP9537	401
Pembina Commingled MFP9537	2 097
Willesden Green Commingled MFP9537	811
Total	3 309
Commingled MFP9538	
Carrot Creek Commingled MFP9538	783
Edson Commingled MFP9538	462
Pembina Commingled MFP9535	150
Rosevear Commingled MFP9538	68
Total	1 463
Commingled MFP9501 (Southeast Alberta Gas System)	
Aerial Commingled MFP9501	82
Alderson Commingled MFP9501	10 995
Armada Commingled MFP9501	31
Atlee-Buffalo Commingled MFP9501	433
Badger Commingled MFP9501	32
Bantry Commingled MFP9501	12 023
Berry Commingled MFP9501	1
Bindloss Commingled MFP9501	634
Blackfoot Commingled MFP9501	410
Bow Island Commingled MFP9501	271
Brooks Commingled MFP9501	410
Carbon Commingled MFP9501	697
Cavalier Commingled MFP9501	458
Cessford Commingled MFP9501	4 905
Chain Commingled MFP9501	144
Connemara Commingled MFP9501	3
Connorsville Commingled MFP9501	692
Countess Commingled MFP9501	34 106
Craigmyle Commingled MFP9501	625
Crossfield Commingled MFP9501	41
Davey Commingled MFP9501	245
Delia Commingled MFP9501	339
Drumheller Commingled MFP9501	1 596
Elkwater Commingled MFP9501	697
Elnora Commingled MFP9501	238
Enchant Commingled MFP9501	10
Entice Commingled MFP9501	6 435
Erskine Commingled MFP9501	26
Ewing Lake Commingled MFP9501	84
Eyremore Commingled MFP9501	671
Fenn West Commingled MFP9501	142
Fenn-Big Valley Commingled MFP9501	914
Gadsby Commingled MFP9501	499
Gartley Commingled MFP9501	7
Ghost Pine Commingled MFP9501	887
Gleichen Commingled MFP9501	338
Herronton Commingled MFP9501	979
High River Commingled MFP9501	10
Hussar Commingled MFP9501	6 248
Huxley Commingled MFP9501	379
Jenner Commingled MFP9501	1 663
Joffre Commingled MFP9501	6
Johnson Commingled MFP9501	95
Jumpbush Commingled MFP9501	427
Kitsim Commingled MFP9501	34
Lathom Commingled MFP9501	2 123
Leckie Commingled MFP9501	540
Leo Commingled MFP9501	258
Little Bow Commingled MFP9501	10
Lomond Commingled MFP9501	67
Lone Pine Creek Commingled MFP9501	161

(*continued on next page*)

Table B.5 (*continued*)

Multifield pool **Field and pool**	**Remaining established reserves (10^6 m^3)**
Long Coulee Commingled MFP9501	11
Majorville Commingled MFP9501	422
Matziwin Commingled MFP9501	464
Mcgregor Commingled MFP9501	20
Medicine Hat Commingled MFP9501	37 327
Michichi Commingled MFP9501	262
Mikwan Commingled MFP9501	409
Milo Commingled MFP9501	41
Newell Commingled MFP9501	1 640
Okotoks Commingled MFP9501	93
Pageant Commingled MFP9501	8
Parflesh Commingled MFP9501	814
PenholdCommingled MFP9501	3
Pollockville Commingled MFP9501	1
Princess Commingled MFP9501	7 175
Queenstown Commingled MFP9501	43
Rainier Commingled MFP9501	9
Redland Commingled MFP9501	566
Rich Commingled MFP9501	280
Rockyford Commingled MFP9501	1 618
Ronalane Commingled MFP9501	61
Rowley Commingled MFP9501	447
Rumsey Commingled MFP9501	28
Seiu Lake Commingled MFP9501	431
Shouldice Commingled MFP9501	591
Silver Commingled MFP9501	8
Stettler Commingled MFP9501	85
Stettler North Commingled MFP9501	24
Stewart Commingled MFP9501	508
Suffield Commingled MFP9501	9 507
Swalwell Commingled MFP9501	401
Three Hills Creek Commingled MFP9501	674
Trochu Commingled MFP9501	177
Twining Commingled MFP9501	1 674
Verger Commingled MFP9501	3 739
Vulcan Commingled MFP9501	65
Wayne-Rosedale Commingled MFP9501	7 668
West Drumheller Commingled MFP9501	46
Wimborne Commingled MFP9501	666
Wintering Hills Commingled MFP9501	2 740
Workman Commingled MFP9501	61
Total	**173 999**

Table B.6 Remaining raw ethane reserves as of December 31, 2013

Field	Remaining reserves of marketable gas (10^6 m^3)	Ethane content (mol/mol)	Remaining established reserves of raw ethane	
			Gas (10^6 m^3)	Liquid (10^3 m^3)
Ansell	15 444	0.082	1 394	4 954
Brazeau River	8 340	0.070	695	2 471
Caroline	5 498	0.086	604	2 148
Edson	6 205	0.080	542	1 927
Elmworth	21 130	0.061	1 398	4 968
Ferrier	10 728	0.085	1 014	3 605
Fir	11 106	0.057	689	2 449
Garrington	3 228	0.078	297	1 055
Gilby	3 701	0.075	308	1 095
Golden Spike	2 197	0.127	412	1 465
Harmattan East	7 581	0.085	726	2 580
Judy Creek	3 539	0.156	687	2 444
Kakwa	13 465	0.080	1 180	4 195
Kaybob	3 751	0.093	396	1 407
Kaybob South	14 089	0.072	1 143	4 064
Leduc-Woodbend	2 854	0.142	485	1 723
Pembina	24 155	0.080	2 714	9 649
Pine Creek	7 026	0.071	579	2 057
Pouce Coupe South	14 825	0.048	785	2 791
Rainbow	9 040	0.099	1 203	4 275
Rainbow South	2 608	0.100	380	1 352
Redwater	3 461	0.094	461	1 640
Ricinus	3 844	0.067	295	1 048
Simonette	2 880	0.083	336	1 193
Sinclair	7 934	0.051	445	1 582
Smoky	4 972	0.071	386	1 372
Sundance	24 056	0.068	1 795	6 383
Swan Hills South	3 426	0.167	801	2 846
Sylvan Lake	3 981	0.077	342	1 216
Valhalla	7 915	0.070	608	2 161
Wapiti	34 092	0.055	2 015	7 163
Wayne-Rosedale	9 117	0.033	325	1 154
Wembley	2 551	0.094	296	1 054
Westerose South	5 268	0.083	486	1 727
Wild River	18 340	0.071	1 419	5 045

(continued on next page)

Table B.6 *(continued)*

Field	Remaining reserves of marketable gas ($10^6\ m^3$)	Ethane content (mol/mol)	Remaining established reserves of raw ethane	
			Gas ($10^6\ m^3$)	Liquid ($10^3\ m^3$)
Willesden Green	19 466	0.087	2 239	7 960
Wilson Creek	3 438	0.074	286	1 016
Subtotal	**345 252**	**0.075**	**30 162**	**107 231**
All other fields	**552 285**	**0.031**	**17 271**	**61 402**
Total	**897 537**	**0.052[a]**	**47 433**	**168 633**

[a] Volume weighted average.

Table B.7 Remaining raw reserves of natural gas liquids as of December 31, 2013

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Ansell	15 444	2 241	1 178	2 438	5 857
Ante Creek North	1 387	260	138	409	806
Brazeau River	8 340	1 158	696	1 499	3 353
Caroline	5 498	911	526	818	2 254
Dunvegan	5 550	464	269	454	1 188
Edson	6 205	739	327	318	1 383
Elmworth	21 130	1 645	779	818	3 242
Fenn-Big Valley	2 247	910	395	106	1 412
Ferrier	10 729	1 656	796	757	3 209
Fir	11 106	928	448	618	1 994
Garrington	3 228	477	244	338	1 059
Gilby	3 701	556	282	310	1 149
Golden Spike	2 197	1 208	159	562	1 929
Harmattan East	7 581	1 133	634	902	2 669
Hussar	8 276	384	207	225	816
Judy Creek	3 539	1 653	683	388	2 725
Kakwa	13 465	1 710	815	827	3 381
Karr	3 258	426	199	195	820
Kaybob	3 751	781	375	396	1 551
Kaybob South	14 089	1 834	939	1 095	3 868
Leduc-Woodbend	2 854	1 463	843	475	2 781
Medicine River	2 821	440	214	210	864
Pembina	24 155	5 949	3 030	2 184	11 163
Pine Creek	7 026	925	435	471	1 831
Pouce Coupe South	14 825	1 026	576	625	2 226
Provost	8 374	574	376	269	1 218
Rainbow	9 040	1 860	1 025	1 072	3 958
Rainbow South	2 608	691	320	369	1 380
Redwater	3 461	1 231	772	307	2 310
Ricinus	3 844	480	239	417	1 136
Simonette	2 880	577	335	340	1 251
Sinclair	7 934	554	236	242	1 032
Smoky	4 972	566	265	208	1 039
Sundance	24 056	2 237	990	1 492	4 719

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Table B.7 (*continued*)

Field	Remaining reserves of marketable gas (10^6 m^3)	(10^3 m^3 liquid)			
		Propane	Butanes	Pentanes plus	Total liquids
Swan Hills South	3 426	1 934	889	391	3 213
Sylvan Lake	3 981	541	265	239	1 045
Valhalla	7 915	1 014	537	788	2 339
Virginia Hills	1 203	642	209	80	932
Wapiti	34 092	2 188	838	795	3 820
Waterton	4 536	209	184	1 148	1 541
Wayne-Rosedale	9 117	555	299	360	1 214
Wembley	2 551	574	338	762	1 674
Westerose South	5 268	914	441	435	1 789
Wild River	18 340	1 689	706	1 025	3 420
Willesden Green	19 466	3 881	1 773	1 569	7 223
Wilson Creek	3 438	488	264	346	1 098
Subtotal	**382 904**	**54 307**	**26 486**	**30 087**	**110 880**
All other fields	**514 633**	**22 720**	**12 859**	**14 823**	**50 402**
Total	**897 537**	**77 027**	**39 345**	**44 910**	**161 281**

Appendix C CD – Basic Data Tables

AER staff developed the databases used to estimate the reserves for this report and the CD that accompanies this report (available for $546 from the AER's Order Fulfillment Team). Input has also been obtained from the National Energy Board (NEB). The crude oil and natural gas reserves data tables noted in the following sections present the official reserve estimates of both the AER and NEB for the province of Alberta.

The conventional oil and conventional natural gas reserves, and their respective basic data tables, for year-end 2013 are on the CD as Microsoft Excel spreadsheets. Individual oil and gas pool values are on the first worksheet of each spreadsheet. Oilfield and gas field/strike totals are on the second worksheet. Provincial totals for crude oil and natural gas are on the third worksheet. The pool names on the left side and the column headings at the top of the spreadsheets are locked into place for easy scrolling. All crude oil and natural gas pools are first listed alphabetically by field/strike name and then stratigraphically within the field, with the pools occurring in the youngest reservoir rock listed first. Additionally, the crude bitumen in-place resources and basic data listed in **Table B.1** and **Table B.2** of **Appendix B** are included in Excel format on the CD.

Crude Oil Reserves and Basic Data

The crude oil reserves and basic data spreadsheet lists all nonconfidential pools in Alberta.

Reserves data for single- and multi-mechanism pools are in separate columns. The total is the sum of the multi-mechanism pool reserves data and can be used to determine field and provincial totals. The name of the mechanism type is displayed.

Provincial totals for light-medium and heavy oil pools are listed on a separate worksheet.

Natural Gas Reserves and Basic Data

The natural gas reserves and basic data spreadsheet lists all nonconfidential pools in Alberta.

Basic reserves data are in two columns: pools (individual, undefined, and total) and member pools (separate gas pools overlying a single oil pool or individual gas pools that have been commingled). The total is the sum of the reserves data for all of the related members. Individual pools have a sequence code of 000; undefined pools have a pool code ending in 98 and a unique pool sequence code other than 000; and the total records have a sequence code of 999. Member pools and the total record have the same pool code, with each member pool having a unique pool sequence code and the total record having a sequence code of 999.

Crude Bitumen Resources and Basic Data

The crude bitumen in-place resources and basic data spreadsheet is unchanged from the data tables in last year's report. The oil sands area, oil sands deposit, overburden/zone, oil sands sector/pool, and resource determination method are listed in separate columns. This data is the same as that listed in **Table B.1** and **Table B.2** of **Appendix B**.

General Abbreviations Used in the Reserves and Basic Data Files

ABAND	abandoned
ASSOC	associated gas
BELL	Belloy
BLAIR	Blairmore
BLSKY OR BLSK	Bluesky
BLUE	Blueridge
BNFF	Banff
BOW ISL or BI	Bow Island
BR	Belly River
BSL COLO	Basal Colorado
BSL MANN, BMNV or BMN	Basal Mannville
BSL QTZ	Basal Quartz
CADM or CDN	Cadomin
CARD	Cardium
CDOT	Cadotte
CH LK	Charlie Lake
CLWTR	Clearwater
CLY or COL	Colony
CMRS	Camrose
DBLT	Debolt
DETR	Detrital
ELRSL, ELERS or ELRS	Ellerslie
ELTN or ELK	Elkton
FALH	Falher
GEN PETE or GEN PET	General Petroleum
GETH or GET	Gething
GLAUC or GLC	Glauconitic
GLWD	Gilwood
GRD RAP or GRD RP	Grand Rapids
GSMT	Grosmont
ha	hectare
HFWY	Halfway
JUR or J	Jurassic
KB	kelly bushing
KISK	Kiskatinaw
KR	Keg River
LED	Leduc
LIV	Livingston
LLOYD	Lloydminster
LMNV, LMN or LM	Lower Mannville
LOW or L	lower

LUSC	Luscar
MANN or MN	Mannville
MCM	McMurray
MED HAT	Medicine Hat
MID or M	middle
MILK RIV	Milk River
MSKG	Muskeg
MSL	mean sea level
NGL	natural gas liquids
NIKA	Nikanassin
NIS	Nisku
NON ASSOC	nonassociated gas
NORD	Nordegg
NOTIK, NOTI or NOT	Notikewin
OST	Ostracod
PALL	Palliser
PEK	Pekisko
RK CK	Rock Creek
RUND or RUN	Rundle
SD	sandstone
SHUN	Shunda
SL PT	Slave Point
SPKY	Sparky
ST. ED	St. Edouard
SULPT	Sulphur Point
SW HL	Swan Hills
TV	Turner Valley
UIRE	Upper Ireton
UMNV, UMN or UM	Upper Mannville
UP or U	upper
VIK or VK	Viking
WAB	Wabamun
WBSK	Wabiskaw
WINT	Winterburn
1ST WHITE SPKS or 1WS	First White Specks
2WS	Second White Specks
SG	gas saturation
SHUN	Shunda
SL	surface loss
SL PT	Slave Point
SOLN	solution gas
SPKY	Sparky
ST. ED	St. Edouard

SULPT	Sulphur Point
SUSP	suspended
SW	water saturation
SW HL	Swan Hills
TEMP	temperature
TOT	total
TV	Turner Valley
TVD	true vertical depth
UIRE	Upper Ireton
UMNV, UMN or UM	Upper Mannville
UP or U	upper
VIK or VK	Viking
VOL	volume
WAB	Wabamun
WBSK	Wabiskaw
WINT	Winterburn
WTR DISP	water disposal
WTR INJ	water injection
1ST WHITE SPKS or 1WS	First White Specks
2WS	Second White Specks

Appendix D Drilling Activity in Alberta

Table D.1 Development and exploratory wells, pre-1972–2013; number drilled annually

	Development					Exploratory				Total			
		Crude bitumen											
Year	Successful oil	Commercial	Experimental	Gas	Total[a]	Succesful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
Pre-1972	11 873	*	**	7 869	24 325	1 624	**	3 619	31 639	13 497	**	11 488	55 964
1972	438	*	**	672	1 468	69	**	318	1 208	507	**	990	2 676
1973	472	*	**	898	1 837	109	**	476	1 676	581	**	1 374	3 513
1974	553	*	**	1 222	2 101	82	**	446	1 388	635	**	1 668	3 489
1975	583	*	**	1 367	2 266	81	**	504	1 380	664	**	1 871	3 646
1976	440	*	**	2 044	2 887	112	**	1 057	2 154	552	**	3 101	5 041
1977	524	*	**	1 928	2 778	178	**	1 024	2 352	702	**	2 952	5 130
1978	708	*	**	2 091	3 186	236	**	999	2 387	944	**	3 090	5 573
1979	953	*	**	2 237	3 686	297	**	940	2 094	1 250	**	3 177	5 780
1980	1 229	*	**	2 674	4 425	377	**	1 221	2 623	1 606	**	3 895	7 048
1981	1 044	*	**	2 012	3 504	381	**	1 044	2 337	1 425	**	3 056	5 841
1982	1 149	*	**	1 791	3 353	414	**	620	1 773	1 563	**	2 411	5 126
1983	1 823	*	**	791	2 993	419	**	300	1 373	2 242	**	1 091	4 366
1984	2 255	*	**	911	3 724	582	**	361	1 951	2 837	**	1 272	5 675
1985	2 101	975	229	1 578	5 649	709	593	354	2 827	2 810	1 797	1 932	8 476
1986	1 294	191	75	660	2 783	452	171	311	1 726	1 746	437	971	4 509
1987	1 623	377	132	549	3 212	553	105	380	1 970	2 176	614	929	5 182
1988	1 755	660	54	871	4 082	526	276	610	2 535	2 281	990	1 481	6 617
1989	869	37	24	602	1 897	382	246	660	2 245	1 251	307	1 262	4 142
1990	804	69	30	715	1 999	401	122	837	2 308	1 205	221	1 552	4 307

(continued on next page)

Table D.1 (*continued*)

Year	Development					Exploratory				Total			
	Successful oil	Crude bitumen Commercial	Crude bitumen Experimental	Gas	Total[a]	Succesful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
1991	1 032	91	13	544	2 089	346	51	566	1 808	1 378	155	1 110	3 897
1992	1 428	101	2	335	2 306	368	13	387	1 497	1 796	116	722	3 803
1993	2 402	290	6	1 565	4 919	549	5	763	2 350	2 951	301	2 328	7 269
1994	1 949	143	0	2 799	5 876	700	53	1 304	3 250	2 649	196	4 103	9 126
1995	2 211	828	1	1 910	5 939	496	222	872	2 542	2 707	1 051	2 782	8 481
1996	2 987	1 675	15	1 932	7 728	583	459	732	2 668	3 570	2 149	2 664	10 396
1997	4 210	2 045	8	2 704	10 275	837	645	614	2 937	5 047	2 698	3 318	13 212
1998	1 277	270	6	3 083	5 166	386	500	1 430	3 007	1 663	776	4 513	8 173
1999	1 311	502	0	4 679	6 988	285	351	1 620	2 905	1 596	853	6 299	9 893
2000	2 052	890	2	5473	8 955	466	576	2 033	3 690	2 518	1 468	7 506	12 645
2001	1 703	818	4	7 089	10 127	418	1 115	2 727	4 927	2 121	1 937	9 816	15 054
2002	1 317	1 056	8	5 921	8 586	345	1 222	2 246	4 231	1 662	2 286	8 167	12 817
2003	1 922	1 000	0	9 705	12 982	441	1 610	2 877	5 328	2 363	2 610	12 582	18 310
2004	1 516	859	0	10 768	13 502	486	1 739	3 179	5 742	2 002	2 598	13 947	19 244
2005	1 748	1 158	2	11 157	14 559	554	1 496	3 454	5 825	2 302	2 656	14 611	20 384
2006	1 583	1 147	0	9 883	12 975	601	2 195	3 258	6 323	2 184	3 342	13 141	19 298
2007	1 376	1 376	0	8 174	11 314	393	2 919	1 738	5 388	1 769	4 295	9 912	16 702
2008	1 420	1 205	4	6 838	9 945	300	3 428	1 099	5 076	1 720	4 637	7 937	15 021
2009	785	941	0	3 000	5 050	126	1 270	398	1 930	911	2 211	3 398	6 980
2010	1 979	1 336	0	3 408	7 103	280	1 331	391	2 130	2 259	2 697	3 799	9 233
2011	2 748	1 748	0	1 857	6 820	367	2 372	228	3 074	3 115	4 121	2 085	9 894
2012	2 534	1 787	0	841	5 860	283	2 050	142	2 562	2 817	3 837	983	8 422

(*continued on next page*)

Table D.1 (*continued*)

Year	Development					Exploratory				Total			
	Successful oil	Crude bitumen: Commercial	Crude bitumen: Experimental	Gas	Total[a]	Succesful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
2013	2 301	1 813	0	969	5 690	192	1 884	140	2 281	2 493	3 697	1 109	7 971
Total	**76 281**	**25 388**	**615**	**138 116**	**266 909**	**17 786**	**29 019**	**48 279**	**151 417**	**94 067**	**55 053**	**186 395**	**418 326**

Source: pre-1972—AER corporate database; 1972–1999—*Alberta Oil and Gas Industry Annual Statistics (ST17)*; 2000–2013—*Alberta Drilling Activity Monthly Statistics (ST59)*.

[a] Also includes unsuccessful, service, and suspended wells.

[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production.

* Included in oil.

** Not available.

Table D.2 Development and exploratory wells, pre-1972–2013; kilometres drilled annually

Year	Development					Exploratory				Total			
	Successful oil	Crude bitumen: Commercial	Crude bitumen: Experimental	Gas	Total[a]	Succesful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
Pre-1972	18 843	*	**	11 640	36 991	2 611	**	4 059	26 556	21 459	**	15 699	63 547
1972	608	*	**	461	1 503	99	**	350	1 569	707	**	811	3 072
1973	659	*	**	635	2 053	127	**	465	1 802	786	**	1 100	3 855
1974	708	*	**	816	2 076	115	**	465	1 580	823	**	1 281	3 656
1975	686	*	**	1 020	2 192	107	**	494	1 457	793	**	1 514	3 649
1976	564	*	**	1 468	2 910	147	**	897	1 965	711	**	2 365	4 875
1977	668	*	**	1 299	2 926	188	**	1 029	2 324	856	**	2 328	5 250
1978	934	*	**	1 463	3 298	333	**	1 267	2 828	1 267	**	2 730	6 126
1979	1 387	*	**	1 713	3 840	507	**	1 411	3 073	1 894	**	3 124	6 913
1980	1 666	*	**	2 134	4 716	614	**	1 828	3 703	2 280	**	3 962	8 419
1981	1 270	*	**	1 601	3 598	573	**	1 442	3 172	1 843	**	3 043	6 770
1982	1 570	*	**	1 280	3 601	670	**	747	2 305	2 240	**	2 027	5 906

(continued on next page)

Table D.2 *(continued)*

Year	Development					Exploratory				Total			
	Successful oil	Crude bitumen Commercial	Crude bitumen Experimental	Gas	Total[a]	Succesful oil	Crude bitumen[b]	Gas	Total[a]	Successful oil	Crude bitumen	Gas	Total[a]
1983	2 249	*	**	758	3 834	610	**	407	1 819	2 859	**	1 165	5 653
1984	2 768	*	**	776	4 823	774	**	464	2 407	3 542	**	1 240	7 230
1985	3 030	577	123	1 389	6 373	1 048	99	465	2 962	4 078	799	1 854	9 335
1986	2 000	116	37	742	3 809	622	41	398	2 037	2 622	194	1 140	5 846
1987	2 302	209	68	730	4 250	793	16	518	2 486	3 095	293	1 248	6 736
1988	2 318	376	31	1 049	5 018	695	65	739	2 870	3 013	472	1 788	7 888
1989	1 130	24	13	733	2 622	382	33	747	2 353	1 512	70	1 480	4 975
1990	1 099	46	22	886	2 834	479	18	860	2 339	1 578	86	1 746	5 173
1991	1 307	62	6	641	2 720	346	14	615	1 979	1 653	82	1 256	4 699
1992	1 786	65	2	399	2 965	470	4	409	1 650	2 256	71	808	4 615
1993	3 044	193	7	1 616	5 850	695	2	773	2 585	3 739	202	2 389	8 435
1994	2 696	96	0	2 876	6 958	922	11	1 389	3 702	3 618	107	4 265	10 660
1995	2 856	620	1	1 969	6 702	624	52	995	2 791	3 480	673	2 964	9 493
1996	3 781	1 202	13	2 030	8 372	724	148	814	2 733	4 505	1 363	2 844	11 105
1997	5 380	1 561	8	2 902	11 383	1 080	142	733	2 928	6 460	1 711	3 635	14 311
1998	1 839	445	8	3 339	6 398	537	119	1 780	3 216	2 376	572	5 119	9 614
1999	1 566	401	0	4 319	6 838	390	60	1 620	3 041	1 956	461	5 939	9 879
2000	2 820	940	2	5 169	9 638	582	131	2 486	3 931	3 402	1 073	7 655	13 569
2001	2 454	834	25	6 846	10 840	603	253	3 219	4 857	3 057	1 112	10 065	15 697
2002	1 852	1 043	2	5 983	9 272	462	315	2 541	3 813	2 314	1 360	8 524	13 085
2003	2 727	1 032	0	9 610	13 825	573	388	3 347	4 799	3 300	1 420	12 957	18 624
2004	2 095	1 000	0	10 767	14 284	663	354	3 905	5 297	2 758	1 354	14 672	19 581
2005	2 534	1 353	3	11 519	16 009	792	338	4 616	6 117	3 326	1 694	16 135	22 126

(continued on next page)

Table D.2 *(continued)*

	Development					Exploratory				Total			
	Successful	Crude bitumen				Succesful	Crude			Successful	Crude		
Year	oil	Commercial	Experimental	Gas	Total[a]	oil	bitumen[b]	Gas	Total[a]	oil	bitumen	Gas	Total[a]
2006	2 263	1 305	0	10 549	14 549	903	496	4 720	6 477	3 166	1 801	15 269	21 026
2007	2 045	1 550	0	8 447	12 469	623	751	2 731	4 582	2 668	2 301	11 178	17 051
2008	2 159	1 379	2	7 790	11 758	447	929	1 726	3 478	2 606	2 310	9 516	15 236
2009	1 257	1 033	0	3 852	6 468	194	380	804	1 619	1 451	1 413	4 656	8 087
2010	3 809	1 336	0	5 134	10 653	514	461	848	1 965	4 323	1 797	5 982	12 618
2011	6 106	1 720	0	4 071	12 425	676	870	594	2 373	6 782	2 590	4 665	14 798
2012	6 218	2 179	0	2 536	11 630	591	782	435	2 018	6 809	2 961	2 971	13 648
2013	5 916	2 127	0	2 981	11 822	382	656	515	1 704	6 298	2 783	3 496	13 526
Total	**114 969**	**24 824**	**373**	**147 938**	**327 095**	**25 287**	**7 928**	**60 667**	**149 262**	**140 261**	**33 125**	**208 605**	**476 357**

Source: pre-1972—AER corporate database; 1972–1999—*Alberta Oil and Gas Industry Annual Statistics (ST17)*; 2000–2013—*Alberta Drilling Activity Monthly Statistics (ST59)*.

[a] Also includes unsuccessful, service, and suspended wells.

[b] Includes oil sands evaluation wells and exploratory wells licensed to obtain crude bitumen production.

* Included in oil.

** Not available.

Appendix E Crude Bitumen Pay Thickness and Geological Structure Contour Maps

This appendix contains geological maps from the Crude Bitumen section that have appeared in previous editions of *ST98*. These are the maps that the most recent determinations of in-place resources are based on. Any new mapping will be described in the main body of *ST98* in the first year of reporting.

Regional Map

Sub-Cretaceous Unconformity

The sub-Cretaceous unconformity is the stratigraphic surface that forms the base on which the bitumen-bearing Cretaceous sediments were deposited. **Figure AE.1** is a structure contour map of that surface as it would have appeared at the end of Bluesky/Wabiskaw time. The parts of the Nisku and Grosmont formations that are bitumen bearing are outlined on this map. These Devonian carbonate formations subcrop along the sub-Cretaceous surface and contain bitumen in an updip location along the subcrop edge. Of particular note are the areas on this map identified as having a relative subsea elevation of greater than zero. These areas were still emergent at the end of Bluesky/Wabiskaw time and would have existed as islands within the transgressing northern Boreal Sea.

Peace River Oil Sands Area

Peace River Bluesky-Gething Deposit

The Bluesky-Gething deposit was reassessed for year-end 2006. **Figure AE.2** is the bitumen pay thickness map for the Bluesky-Gething deposit based on cutoffs of 6 mass per cent and 1.5 metres (m) thickness. The Bluesky-Gething is mapped as a single bitumen zone so that the full extent of the deposit at 6 mass per cent can be shown. Also shown on **Figure AE.2** are the paleotopographic highlands as they would have existed at the time of the end of the deposition of the Bluesky Formation. These highlands, composed of carbonate rocks of Devonian and Mississippian age, controlled the deposition of the Bluesky and correspondingly the extent of the reservoir. Oil migrated updip became trapped beneath the overlying Wilrich shales and against the highlands, where it was eventually biodegraded into bitumen.

Athabasca Oil Sands Area

Athabasca Grosmont Deposit

In 2009, the AER updated the previous (1990) resource assessment of the Athabasca Grosmont deposit. Over 1330 wells were used within the study area, which extended from Township 62 to 103 and Range 13, West of the 4th Meridian, to Range 6, West of the 5th Meridian. In its resource assessment, the AER included the bitumen from the Upper Ireton Formation. The Grosmont and the Ireton formations are considered to be in hydraulic communication.

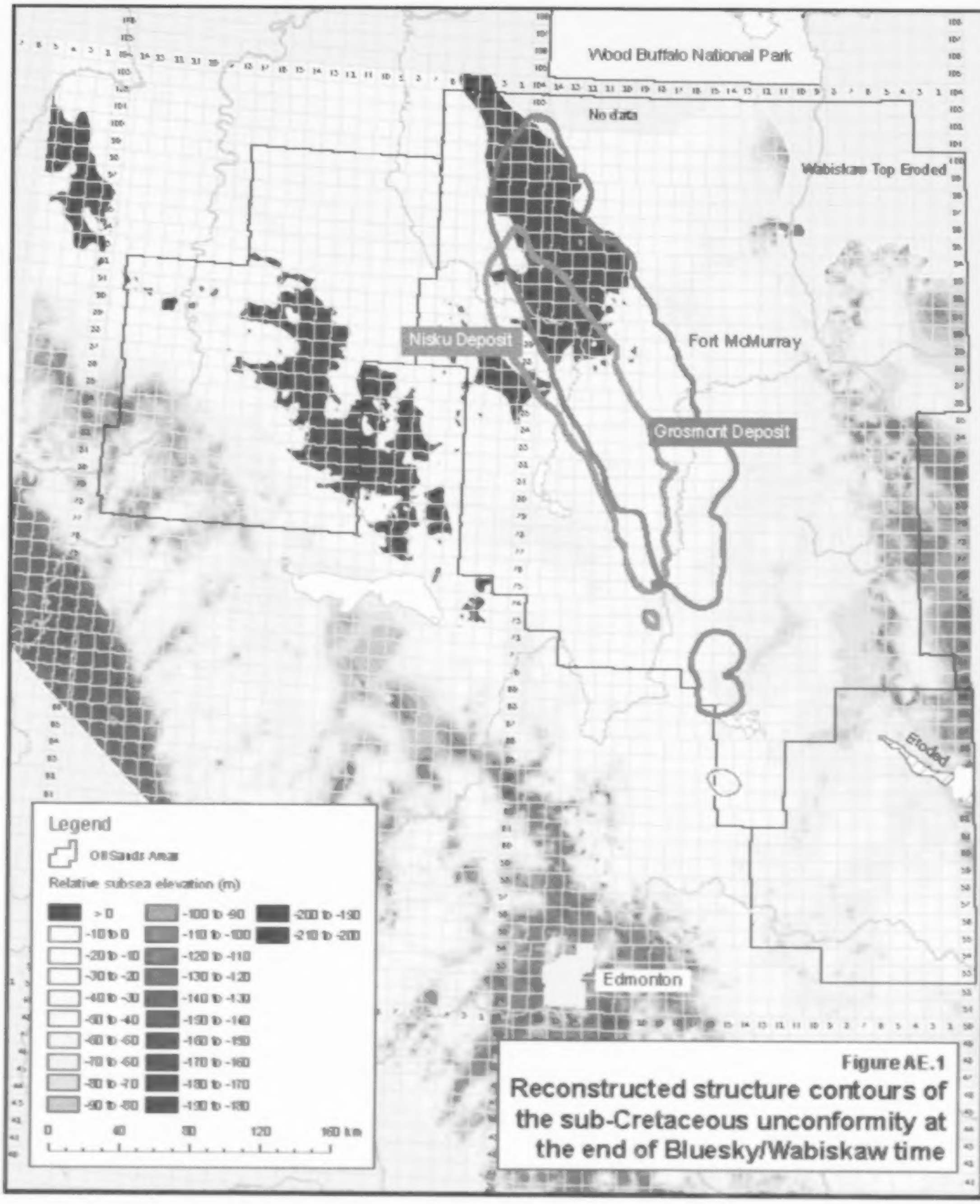


Figure AE.1
Reconstructed structure contours of the sub-Cretaceous unconformity at the end of Bluesky/Wabiskaw time

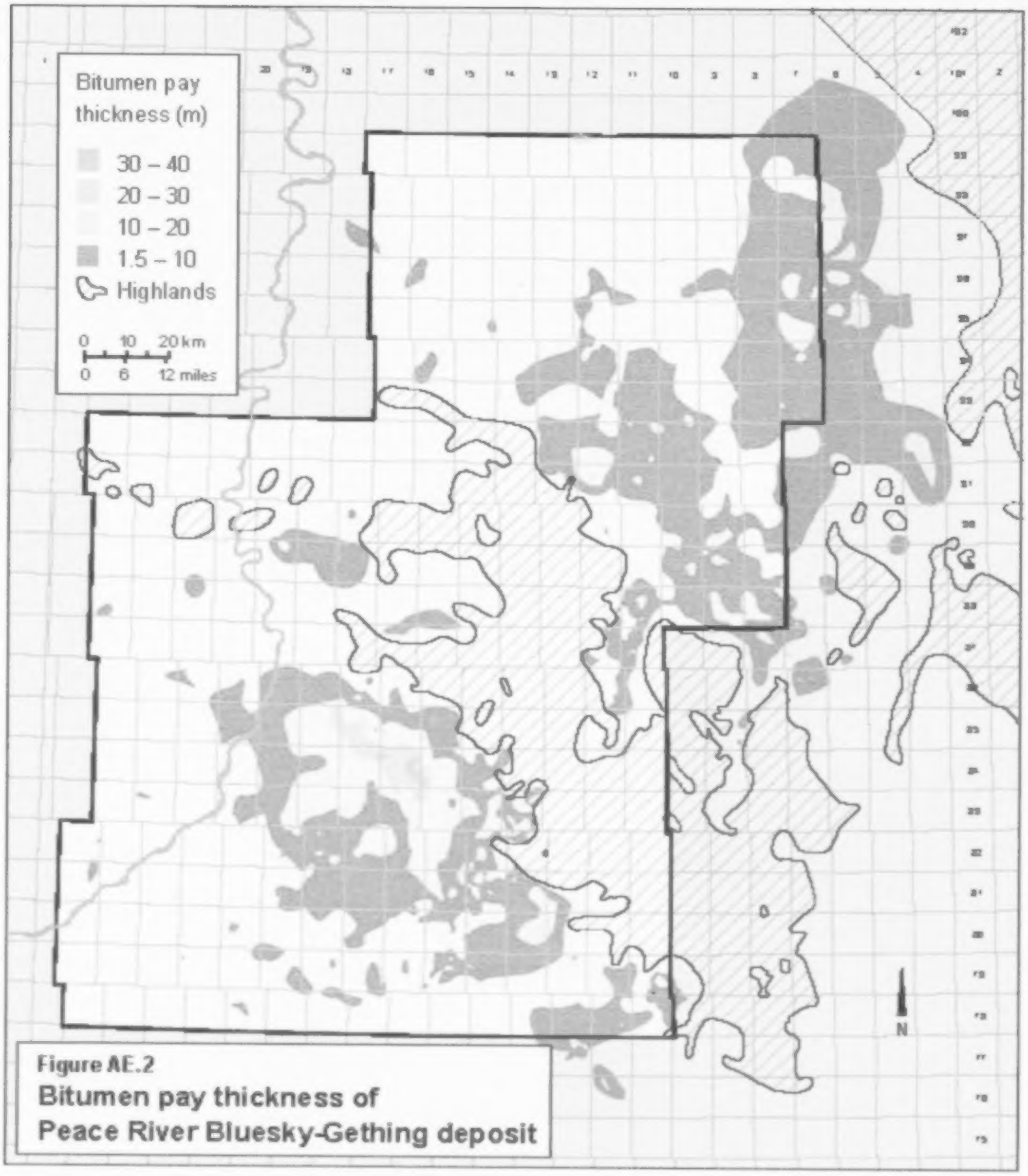


Figure AE.2
Bitumen pay thickness of Peace River Bluesky-Gething deposit

The Grosmont Formation is a late-Devonian shallow-marine to peritidal platform carbonate consisting of four recognizable units within the deposit: the Grosmont A, B, C, and D. All of the hydrocarbons are located in an updip position, structurally trapped along the erosional edge and contained by the overlying Clearwater Formation. **Figure AE.3** is the cumulative bitumen net pay isopachs for the entire Grosmont deposit.

Athabasca Wabiskaw-McMurray Deposit

In 2003, the AER completed a reassessment of the Wabiskaw-McMurray using geological information from over 13 000 wells and bitumen content evaluations from over 9000 wells to augment the over 7000 boreholes already assessed within the surface mineable area (SMA; see below for details). In 2005 and 2007, nearly 700 and 2700 new wells respectively, mostly outside the SMA, were added to the reassessment, and the volumes and maps were revised. In 2008, about 2500 additional wells outside the SMA and about 18 000 wells inside the SMA were added. In 2009, about 1700 wells, including about 350 from within the SMA, were added.

Figure AE.4 is a bitumen pay thickness map of the Wabiskaw-McMurray deposit revised for year-end 2009 based on cutoffs of 6 mass per cent and 1.5 m thickness. In this map, the deposit is treated as a single bitumen zone and the pay is accumulated over the entire geological interval. Also shown is the extent of the SMA, an AER-defined area of 51½ townships north of Fort McMurray covering that part of the Wabiskaw-McMurray deposit where the total overburden thickness generally does not exceed 65 m. This designation is for resource administration purposes and carries no regulatory authority. That is to say that while mining activities are likely to be confined to the SMA, they may occur outside the area's boundaries, while in situ activities may occur within the SMA. Because the extent of the SMA is defined using township boundaries, it incorporates a few areas containing deeper bitumen resources that are more amenable to in situ recovery. The AER has generated a line that generally separates the mineable portion of the deposit from the in situ portion, and that line is shown in **Figure AE.4**.

Athabasca Upper, Middle, and Lower Grand Rapids Deposits

The 2011 year-end review for the three Athabasca Grand Rapids deposits (Upper, Middle, and Lower), **Figures AE.5**, **AE.6**, and **AE.7**, included an evaluation of 3575 wells for stratigraphic tops and 1887 for reservoir parameters. The study area covered Townships 73 to 87 within Range 17, West of the 4th Meridian, to Range 1, West of the 5th Meridian. The reassessment resulted in in-place bitumen resources being increased from 8678 10^6 m^3 to 9274 10^6 m^3 for the Grand Rapids deposits. This represents a 7 per cent increase, which is attributed to an increased number of wells drilled in the area.

The Grand Rapids Formation is interpreted as a series of prograding sequences of shoreface sands and shales. Informally the formation has been divided into Upper, Middle, and Lower sequences, with the boundaries defined by laterally extensive marine shales (maximum flooding surfaces). The Athabasca Upper Grand Rapids accounts for the majority (approximately 60 per cent) of the bitumen-bearing sand within this formation (**Table R3.3**). The Grand Rapids Formation is bounded above and below by the marine shales of the Joli Fou and Clearwater formations, respectively.

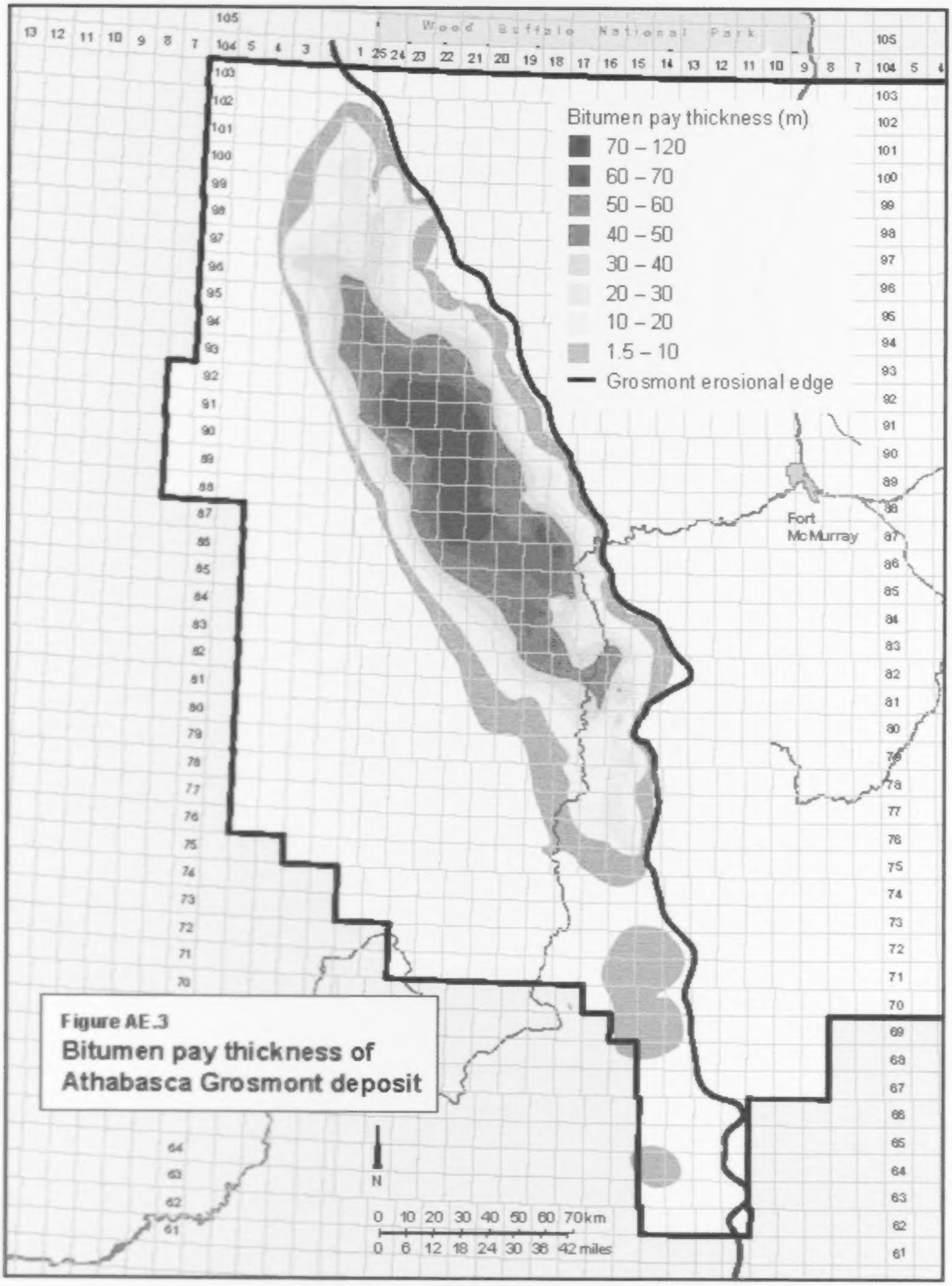


Figure AE.3
Bitumen pay thickness of Athabasca Grosmont deposit

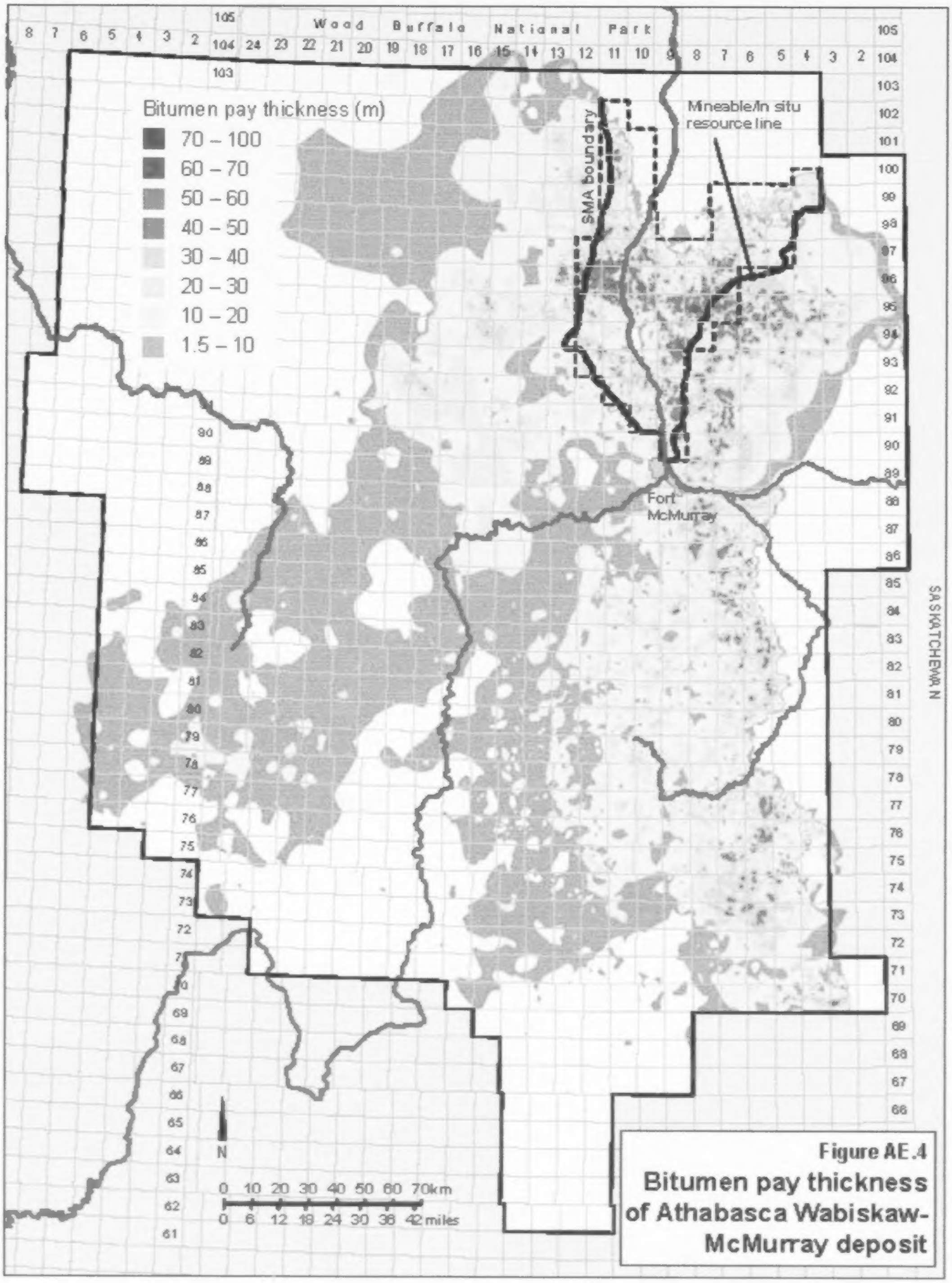


Figure AE.4
Bitumen pay thickness of Athabasca Wabiskaw-McMurray deposit

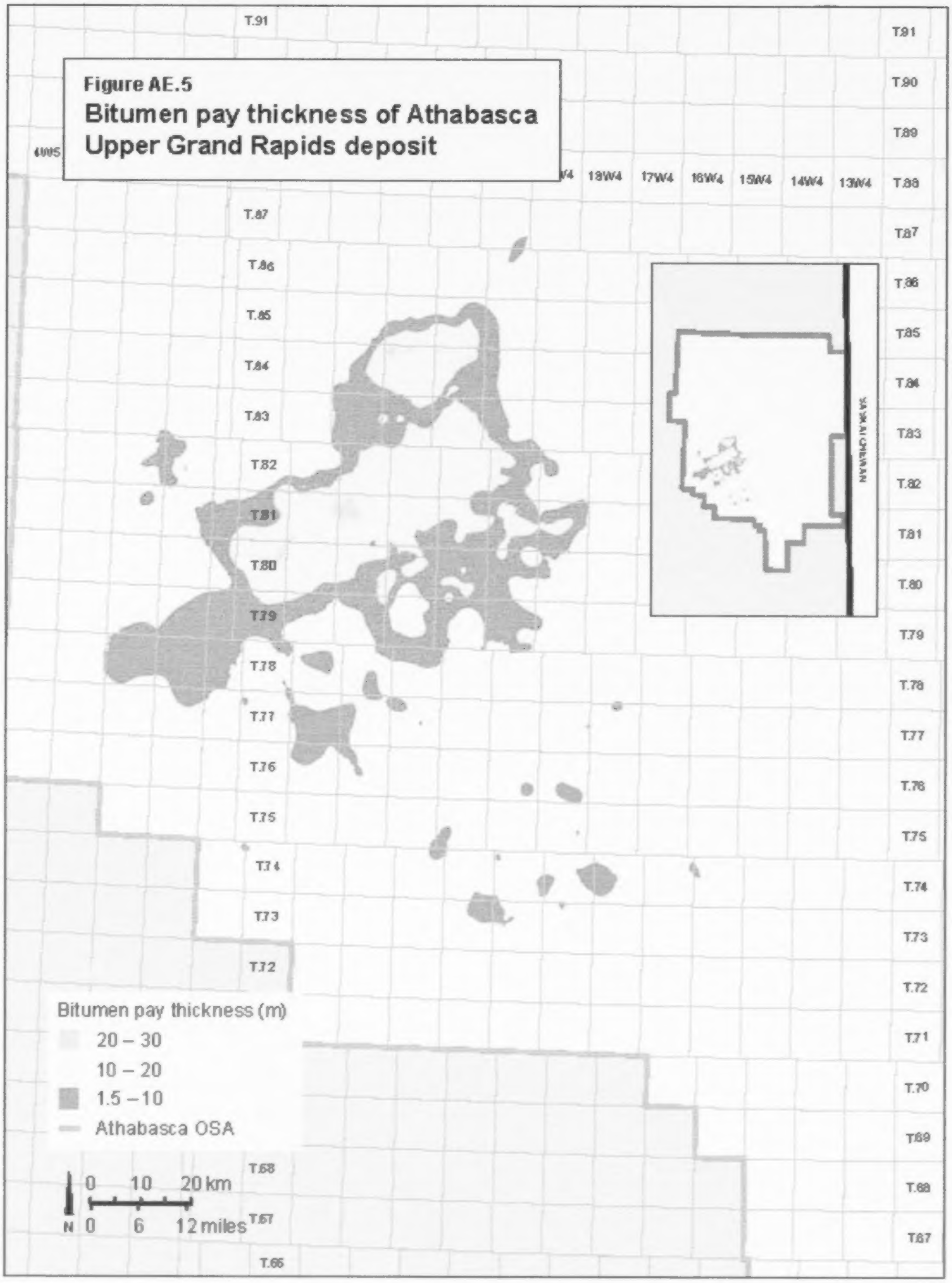
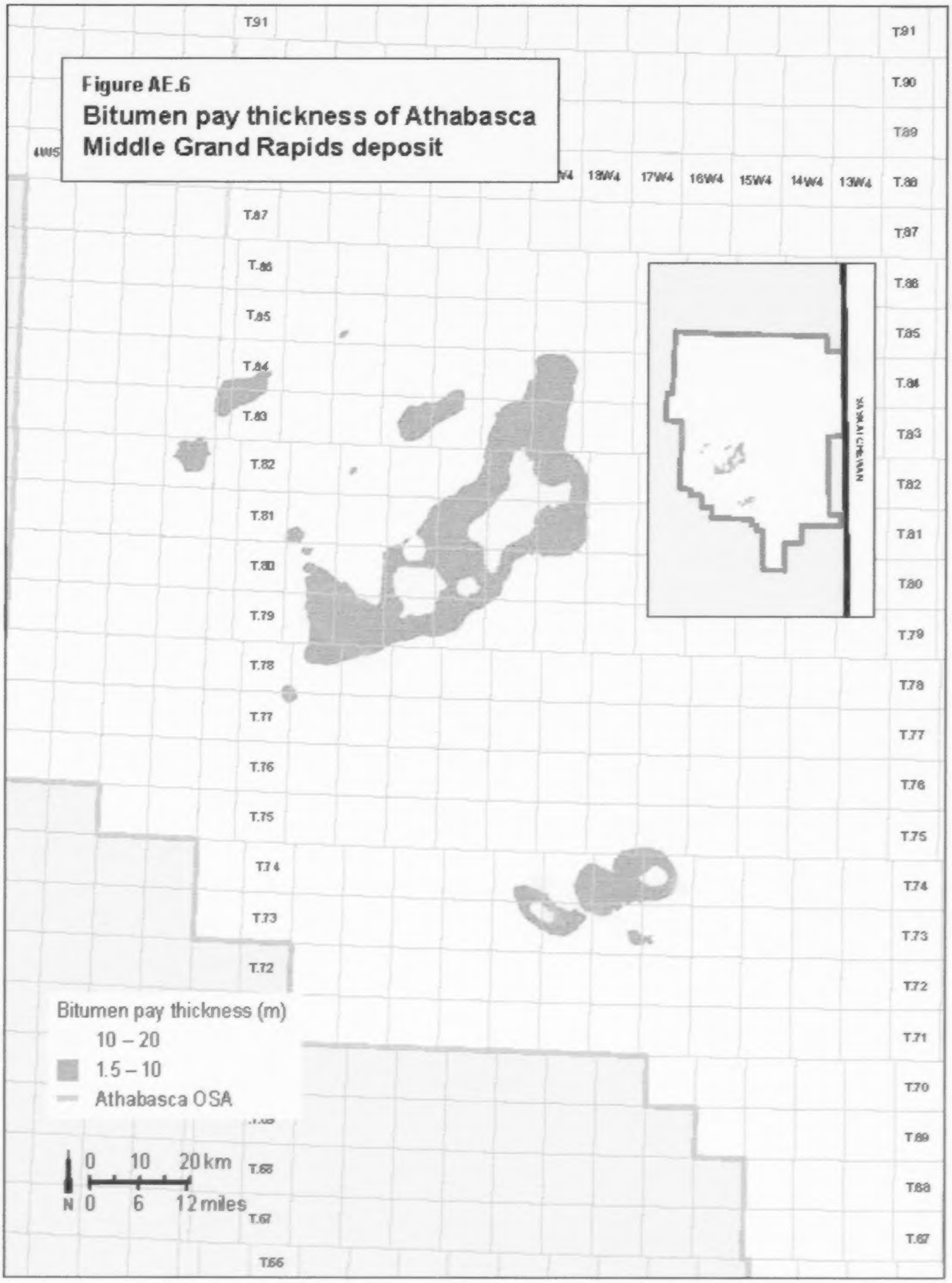


Figure AE.5
Bitumen pay thickness of Athabasca Upper Grand Rapids deposit
Bitumen pay thickness (m)
20 – 30
10 – 20
1.5 – 10
Athabasca OSA
0 10 20 km
0 6 12 miles
N
SASKATCHEWAN
18W4
17W4
16W4
15W4
14W4
13W4
T.91
T.90
T.89
T.88
T.87
T.86
T.85
T.84
T.83
T.82
T.81
T.80
T.79
T.78
T.77
T.76
T.75
T.74
T.73
T.72
T.71
T.70
T.69
T.68
T.67
T.66

Figure AE.6
Bitumen pay thickness of Athabasca Middle Grand Rapids deposit



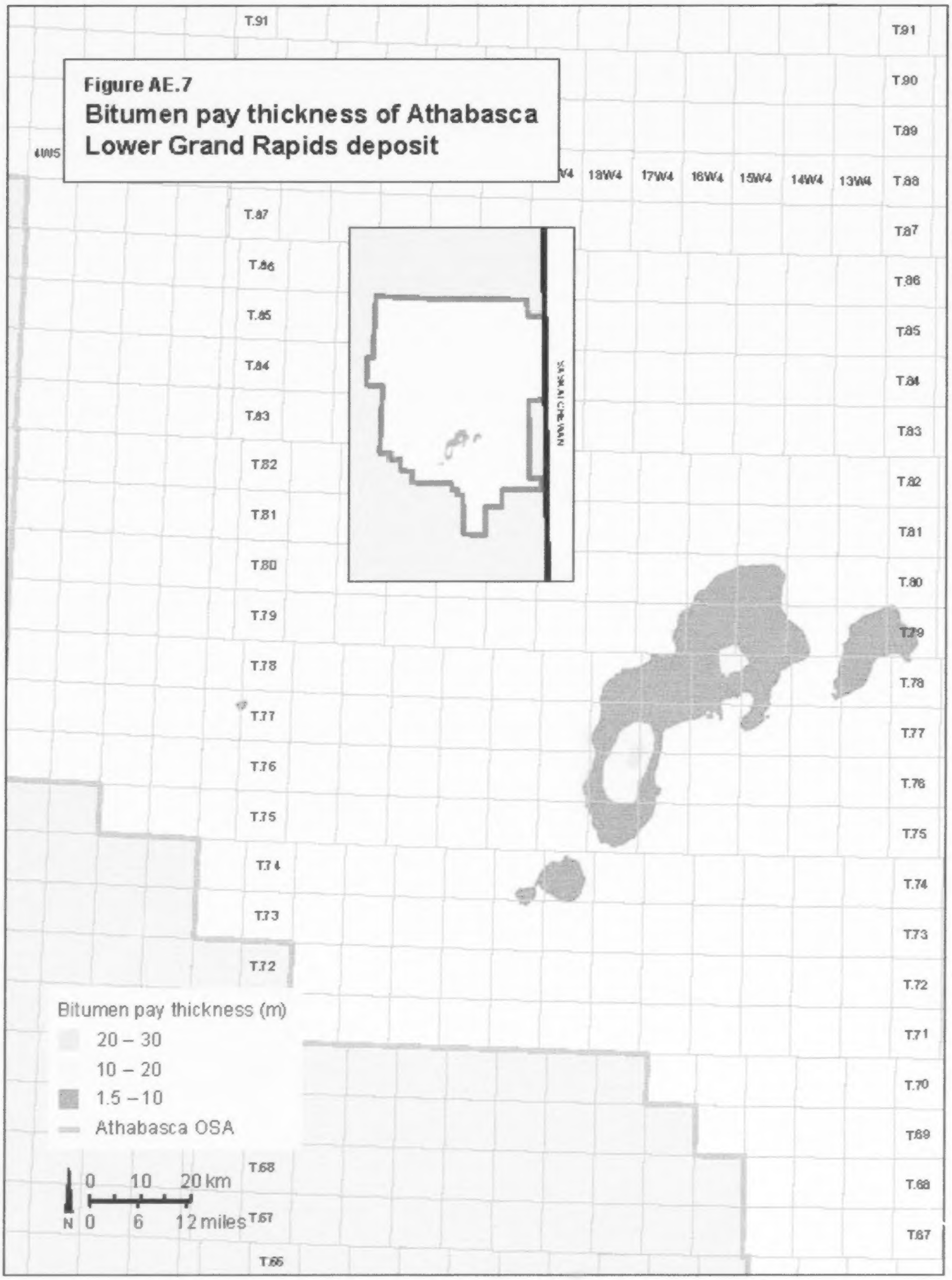


Figure AE.7
Bitumen pay thickness of Athabasca Lower Grand Rapids deposit
Bitumen pay thickness (m)
20 – 30
10 – 20
1.5 – 10
Athabasca OSA
0 10 20 km
0 6 12 miles
N
SASKATCHEWAN
18W4
17W4
16W4
15W4
14W4
13W4
4W5
T.91
T.90
T.89
T.88
T.87
T.86
T.85
T.84
T.83
T.82
T.81
T.80
T.79
T.78
T.77
T.76
T.75
T.74
T.73
T.72
T.71
T.70
T.69
T.68
T.67
T.66

Athabasca Nisku Deposit

The 2011 year-end review of the Athabasca Nisku Formation, **Figure AE.8**, included an evaluation of 560 wells for stratigraphic tops and 130 wells for reservoir parameters. The AER, in its evaluation of the Nisku Formation, included bitumen from the Blueridge Formation. The Calmar Formation is a shale within this deposit. Information to date indicates that the Calmar Formation is a potential baffle. The study area covered Townships 75 to 96 within Range 18, West of the 4th Meridian, to Range 4, West of the 5th Meridian. The reassessment resulted in in-place bitumen resources being increased from 10 330 10^6 m^3 to 16 232 10^6 m^3. This represents a 57 per cent increase, which is attributed to an increase in well data and the expansion of the delineated resource area.

The Nisku Formation is a late-Devonian shelf carbonate. Early dolomitization and subsequent leaching of meteoric waters led to karsting and the creation of vugs and caves. The Nisku is a naturally fractured reservoir. Similar to the Grosmont Formation, the bitumen in the Nisku is contained in a triple porosity system within the vugs, the fractures, and the rock matrix. Hydrocarbons were probably trapped structurally along the updip erosional edge before degradation to bitumen.

Cold Lake Oil Sands Area

Sub-Cretaceous Unconformity

Figure AE.9 is a map of the reconstructed structure contours for the sub-Cretaceous unconformity in the northern part of the Cold Lake Oil Sands Area as they would have been at the beginning of deposition of the Mannville Clearwater Formation.

Cold Lake Wabiskaw-McMurray Deposit

For year-end 2005, the AER reassessed the northern portion of the Cold Lake Wabiskaw-McMurray deposit. Stratigraphic information and detailed petrophysical evaluations from almost 400 wells were used in this reassessment. **Figure AE.10** is the bitumen pay thickness map for the Cold Lake Wabiskaw-McMurray deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. Although the Wabiskaw-McMurray contains some regionally mappable internal seals, and therefore several bitumen zones, this map was produced as a single bitumen zone to provide a regional overview of the distribution of the bitumen-saturated sands. A cutoff of 6 mass per cent bitumen was used.

Cold Lake Clearwater Deposit

For year-end 2005, the AER completed a reassessment of the Clearwater deposit. **Figure AE.11** is a bitumen pay thickness map for the Clearwater deposit based on cutoffs of 6 mass per cent and 1.5 m thickness. As the Clearwater does not contain regionally mappable internal shales or mudstones that can act as seals, the deposit is mapped as a single bitumen zone.

Cold Lake Upper and Lower Grand Rapids Deposits

A reassessment for year-end 2009 of the Upper and Lower Grand Rapids deposits included a review of some 12 000 wells for stratigraphic tops and net pay. The study area from Township 52 to 66 replaced the area used in the previous assessment. Stratigraphy and net pay determination were completed for each Grand Rapids zone: Colony, McLaren, Waseca, Sparky, General Petroleum (GP), Rex, and Lloydminster.

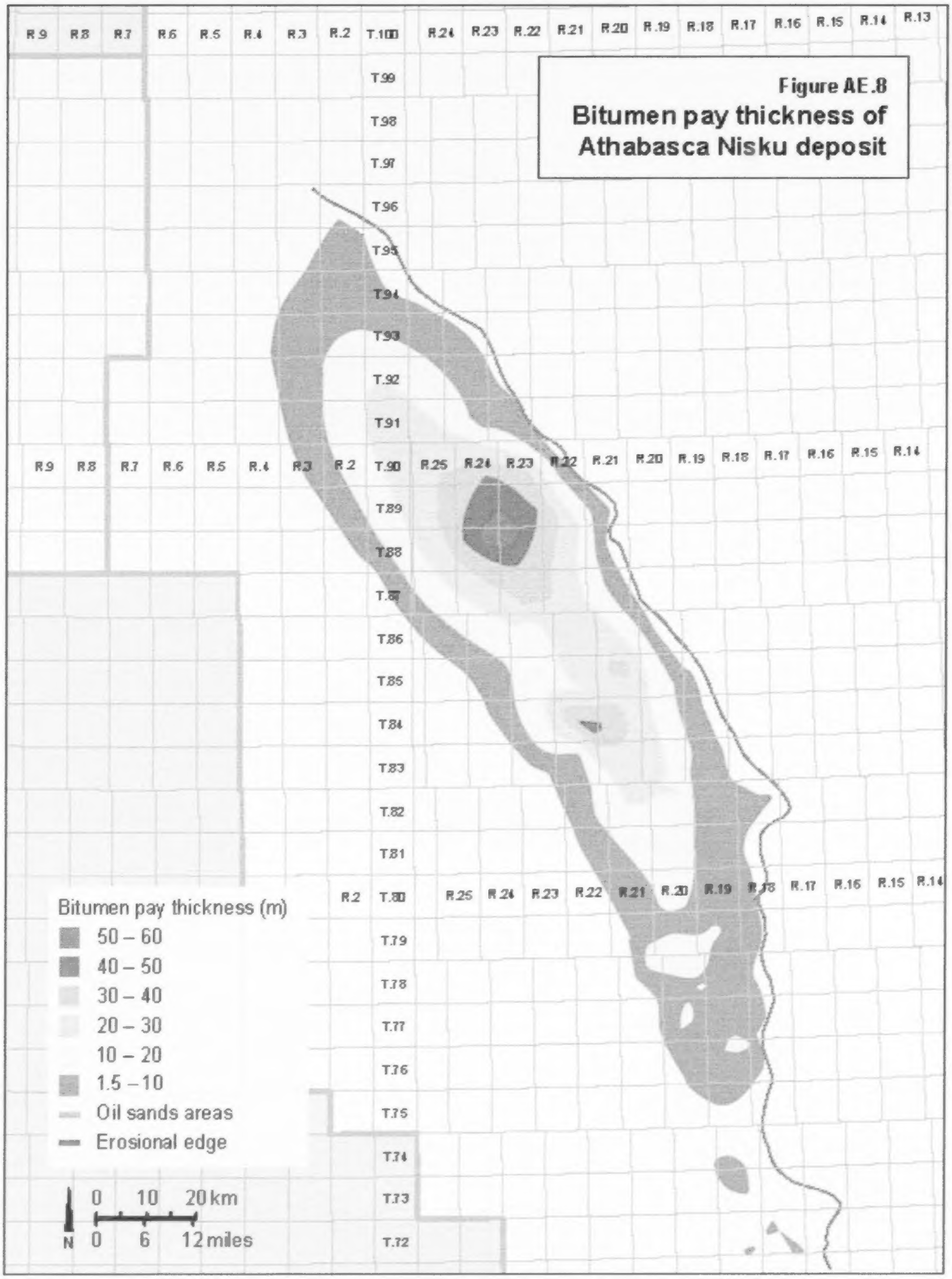


Figure AE.8
Bitumen pay thickness of Athabasca Nisku deposit
Bitumen pay thickness (m)
50 – 60
40 – 50
30 – 40
20 – 30
10 – 20
1.5 – 10
Oil sands areas
Erosional edge
0 10 20 km
0 6 12 miles
N

Although crude bitumen within both Grand Rapids deposits is pervasive through much of the Cold Lake Oil Sands Area, the developable resource (primary bitumen for the most part) is generally associated with Paleozoic highs. **Figures AE.12** and **AE.13** are maps of the cumulative net pay isopachs for the Upper Grand Rapids deposit and the Lower Grand Rapids deposit respectively. The net pay interpretations and volumetric calculations were completed for each zone and were then summed for the relevant deposit. The Colony, Waseca, and McLaren are included in the Upper Grand Rapids, and the Sparky, GP, Rex, and Lloydminster are included in the Lower Grand Rapids.

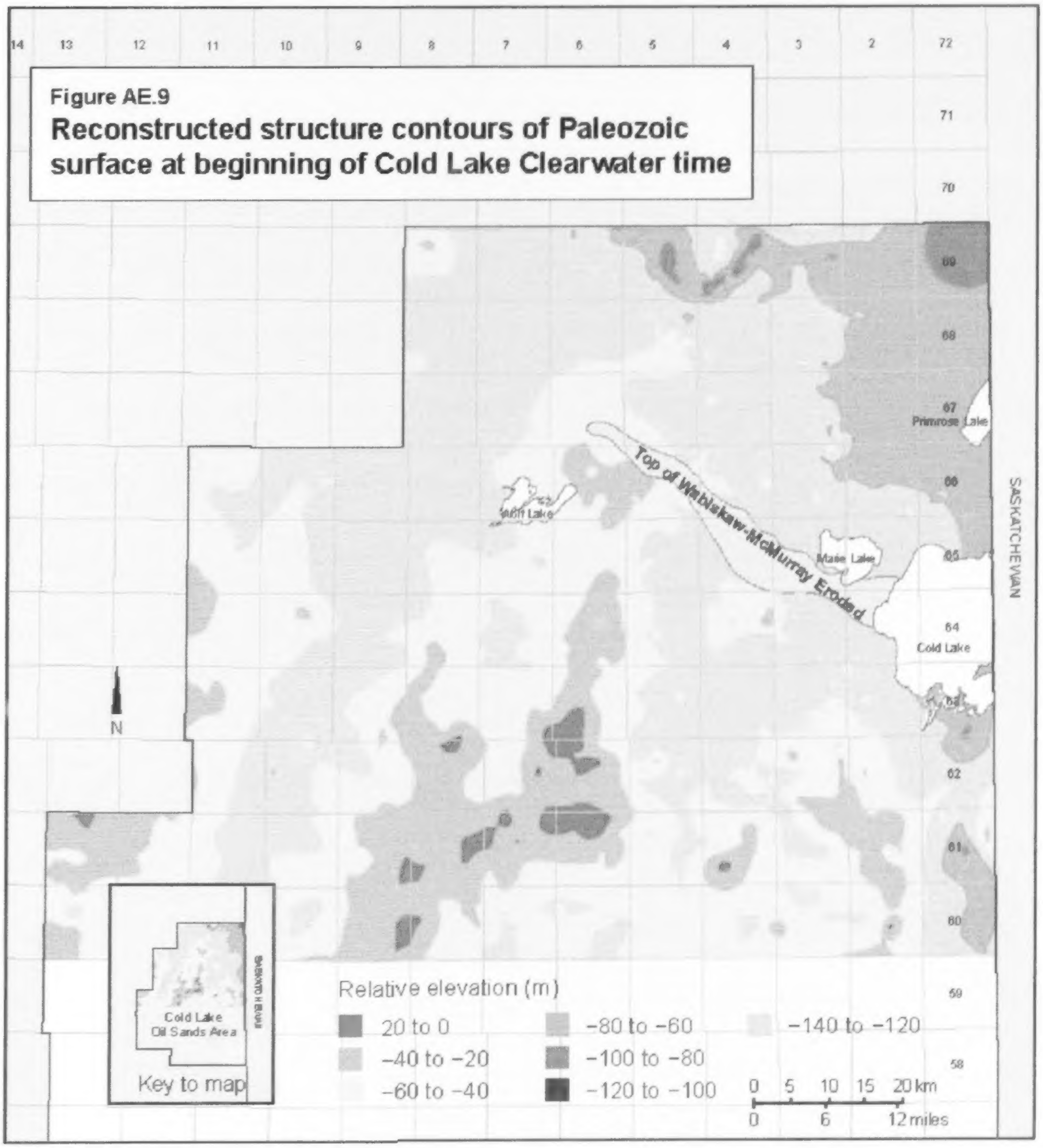


Figure AE.9
Reconstructed structure contours of Paleozoic surface at beginning of Cold Lake Clearwater time

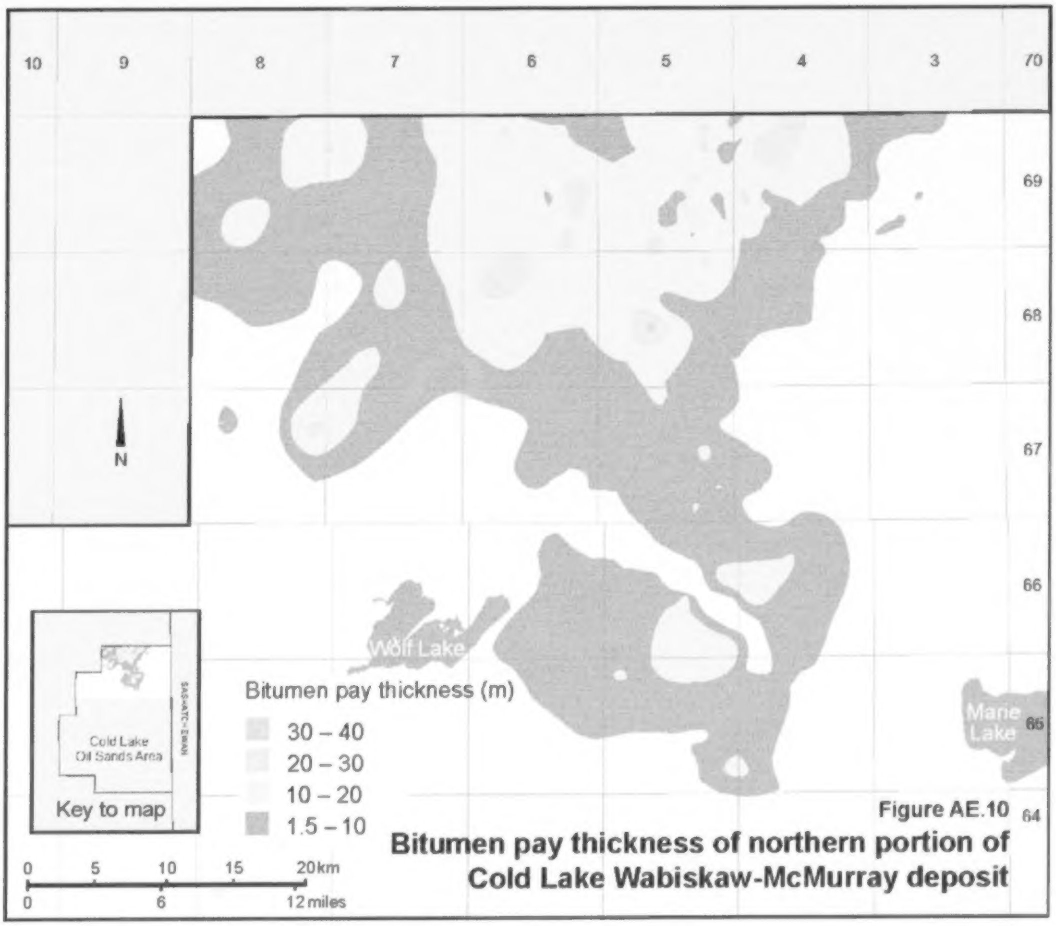


Figure AE.10
Bitumen pay thickness of northern portion of Cold Lake Wabiskaw-McMurray deposit

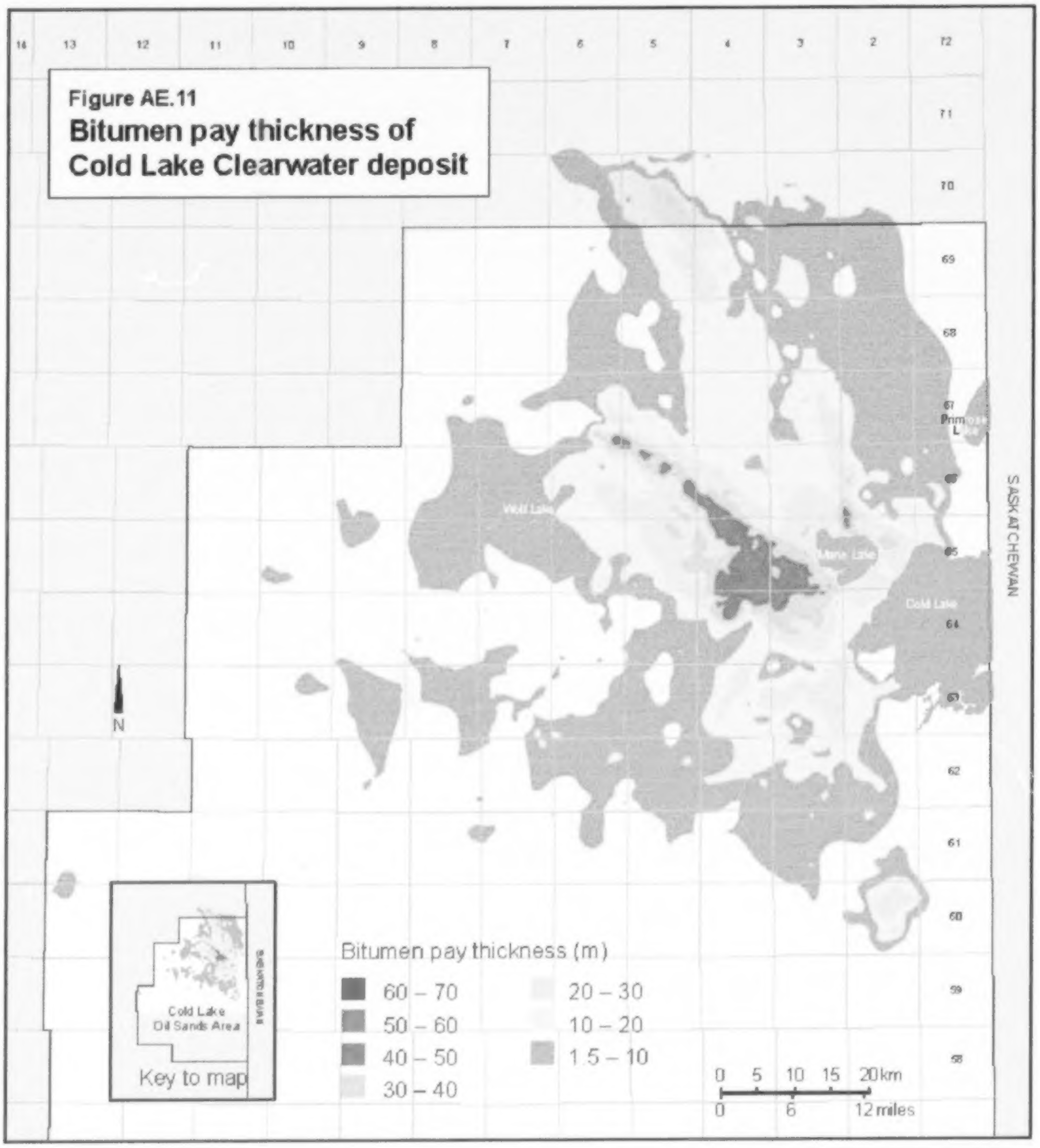


Figure AE.11
Bitumen pay thickness of Cold Lake Clearwater deposit
Bitumen pay thickness (m)
60 – 70
50 – 60
40 – 50
30 – 40
20 – 30
10 – 20
1.5 – 10
Key to map
Cold Lake Oil Sands Area
SASKATCHEWAN
N
0 5 10 15 20km
0 6 12 miles

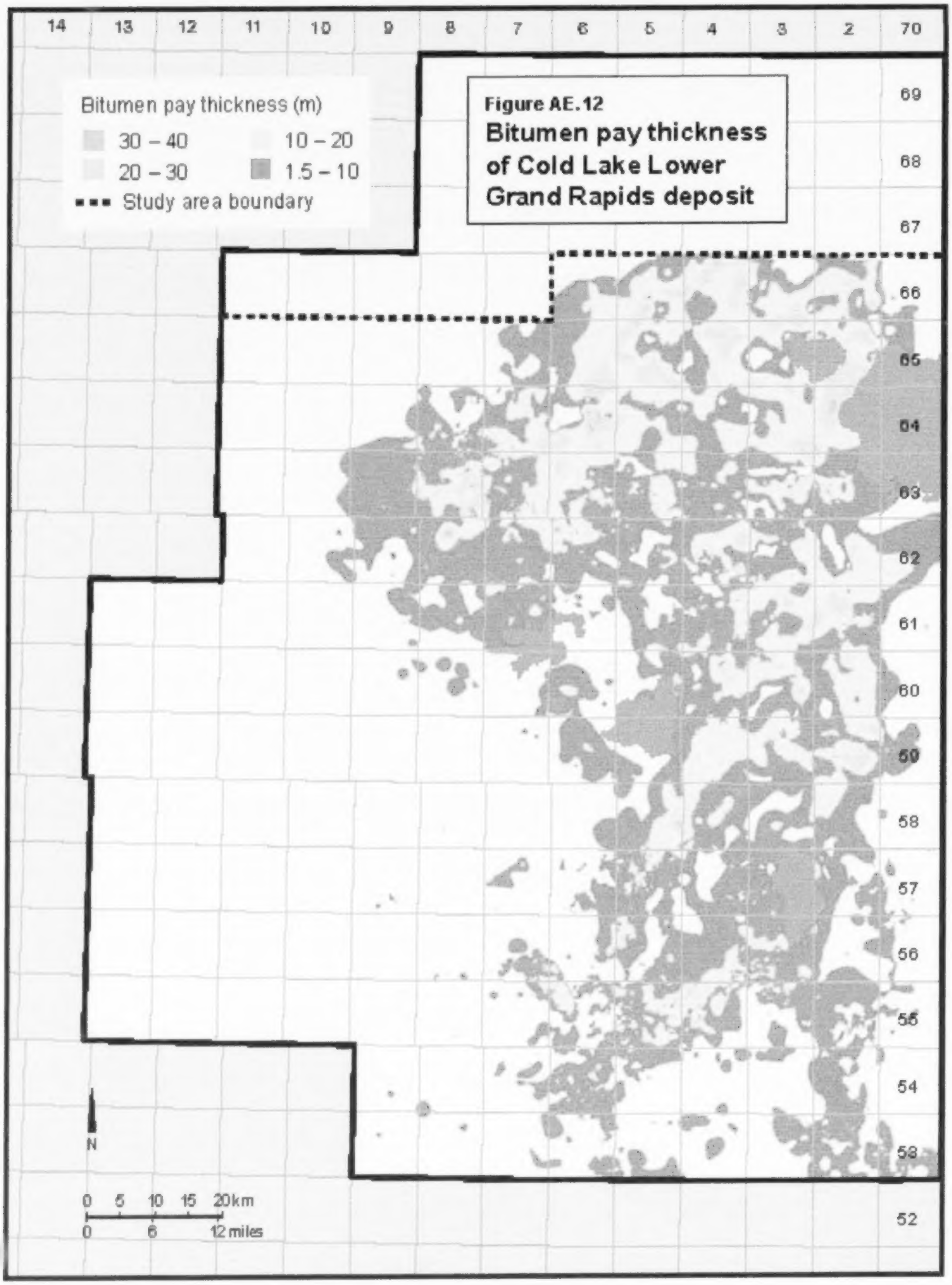


Figure AE.12
Bitumen pay thickness of Cold Lake Lower Grand Rapids deposit

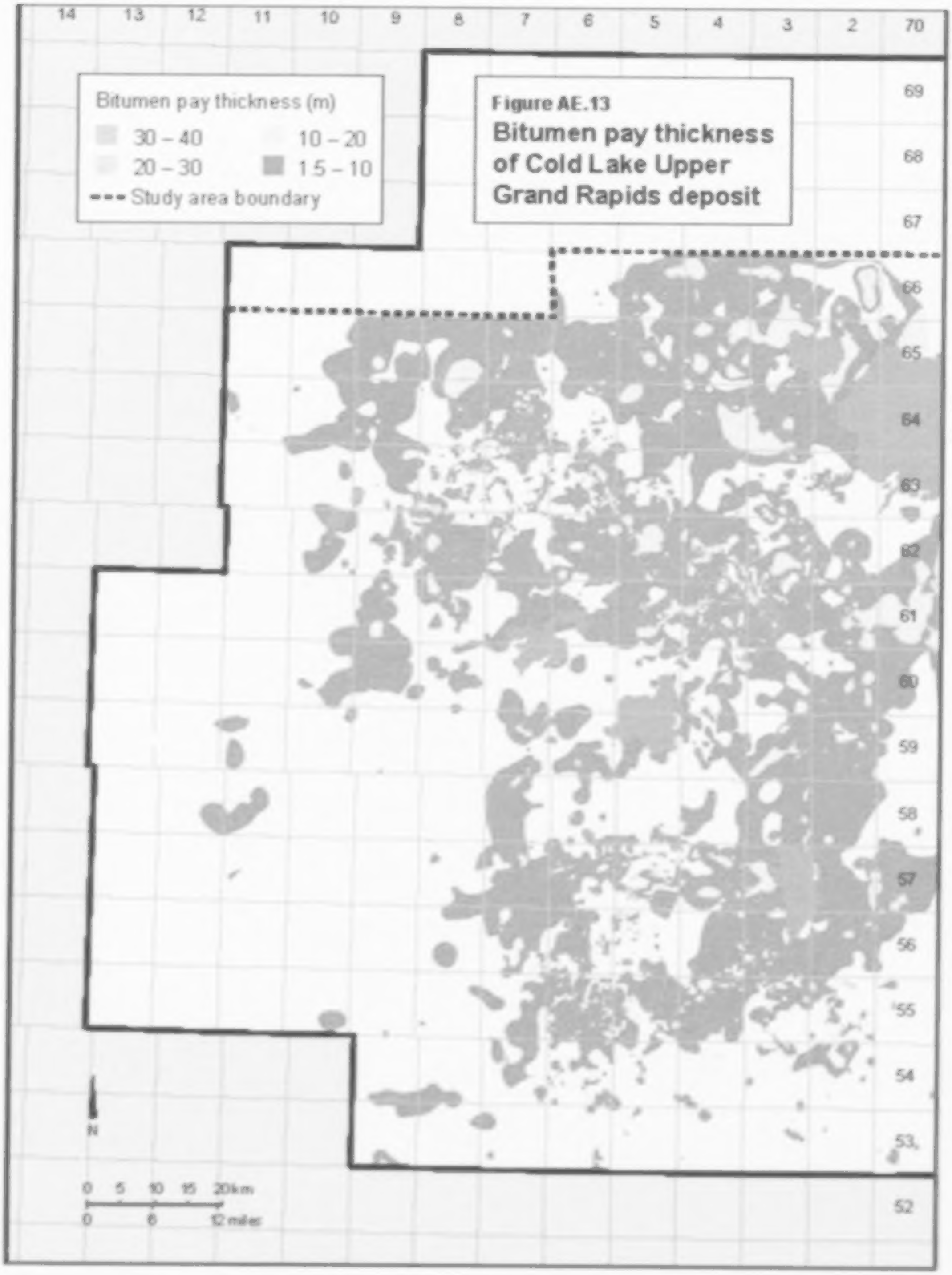


Figure AE.13
Bitumen pay thickness of Cold Lake Upper Grand Rapids deposit

Appendix F Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential

In 2012, the AER completed a study entitled *ERCB/AGS Open File Report 2012-06: Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential*. The results of that study have been incorporated into this report, and the figures showing the medium (P_{50}) in-place resource values of natural gas, natural gas liquids, and crude oil for each of the six formations detailed in that study are shown in the six figures in this appendix.

Figure AF.1

P50 gas, oil, and liquids initial in-place for the Duvernay Formation

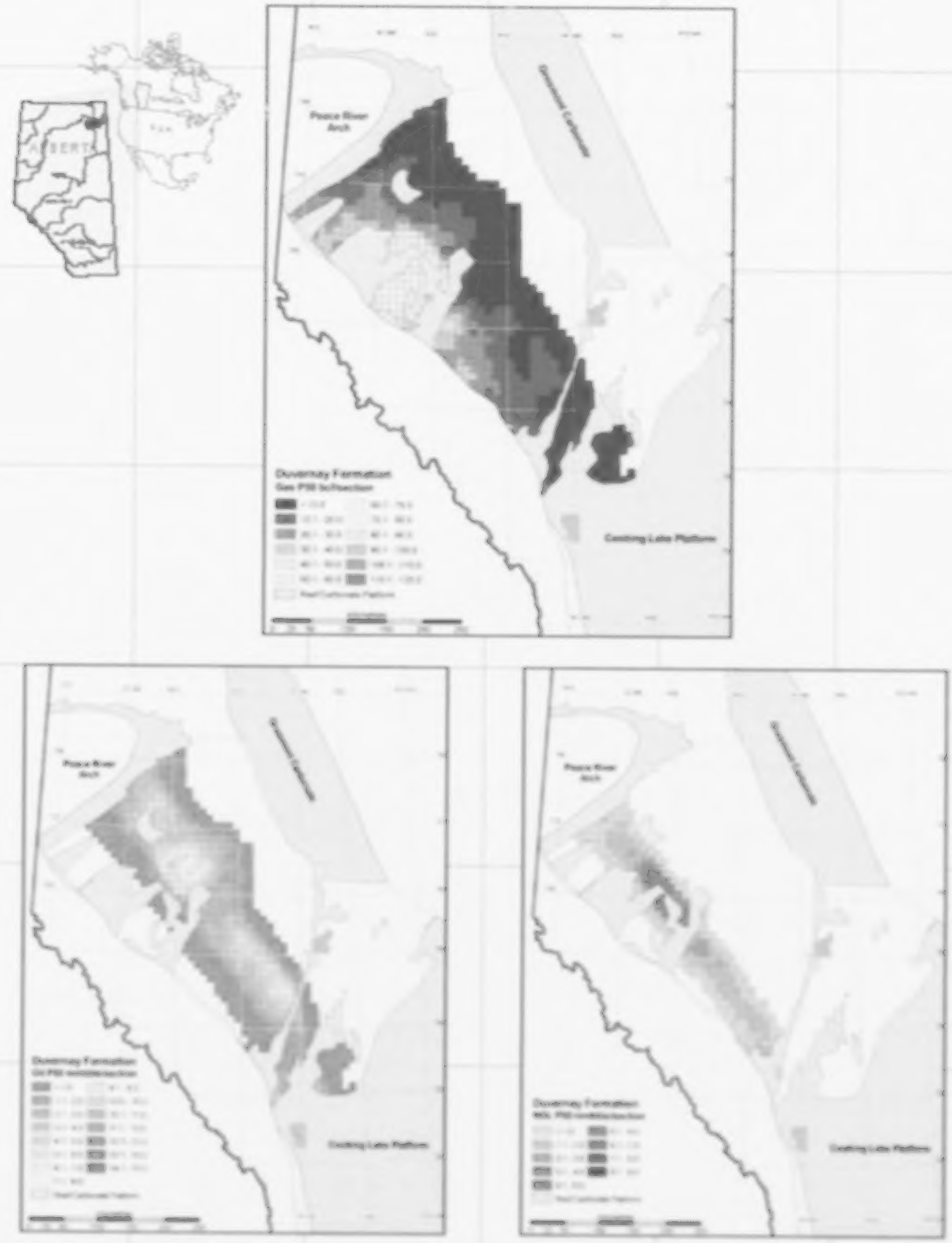


Figure AF.2

P50 gas, oil, and liquids initial in-place for the Muskwa Formation

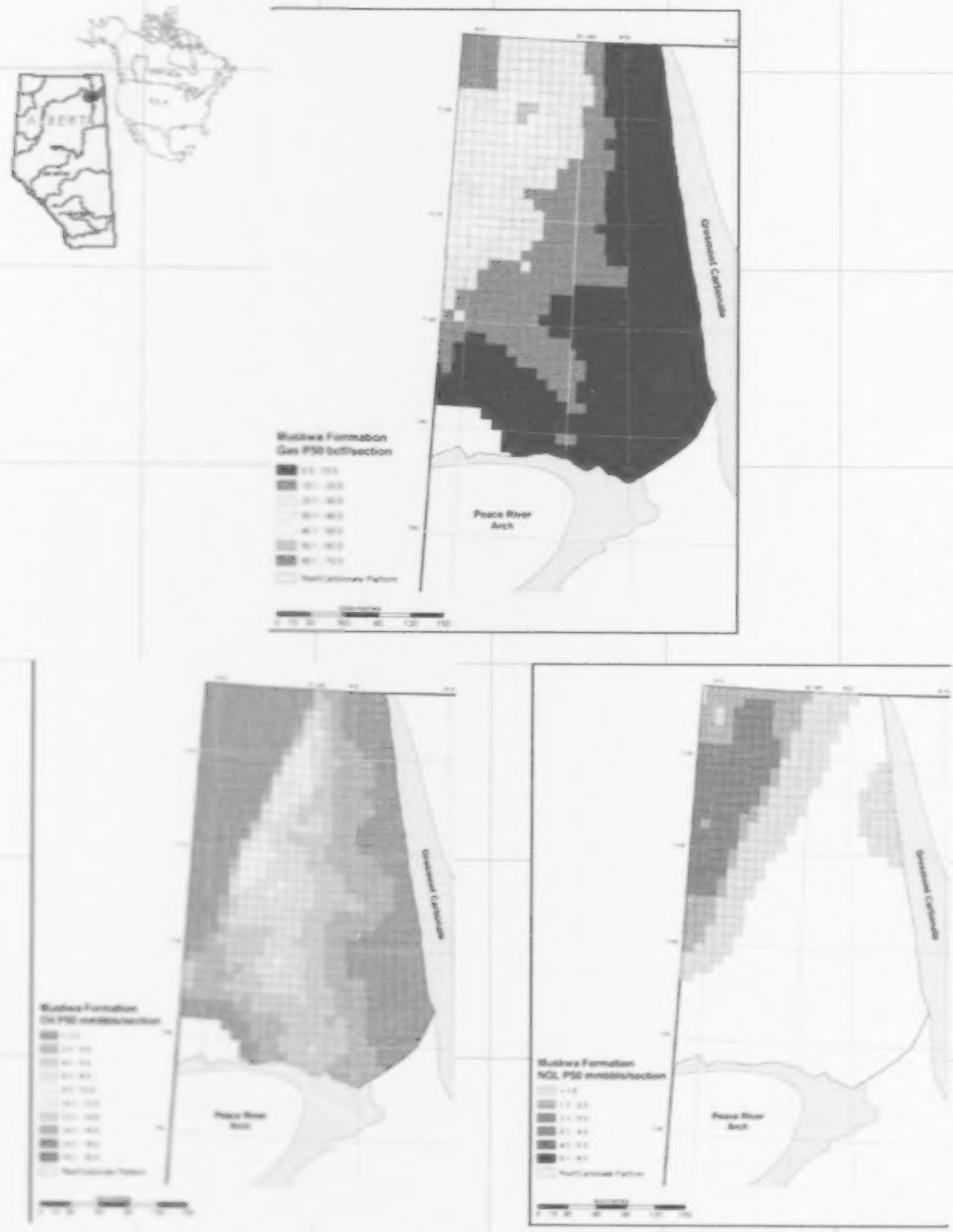


Figure AF.3

P50 gas, oil, and liquids initial in-place for the Montney Formation

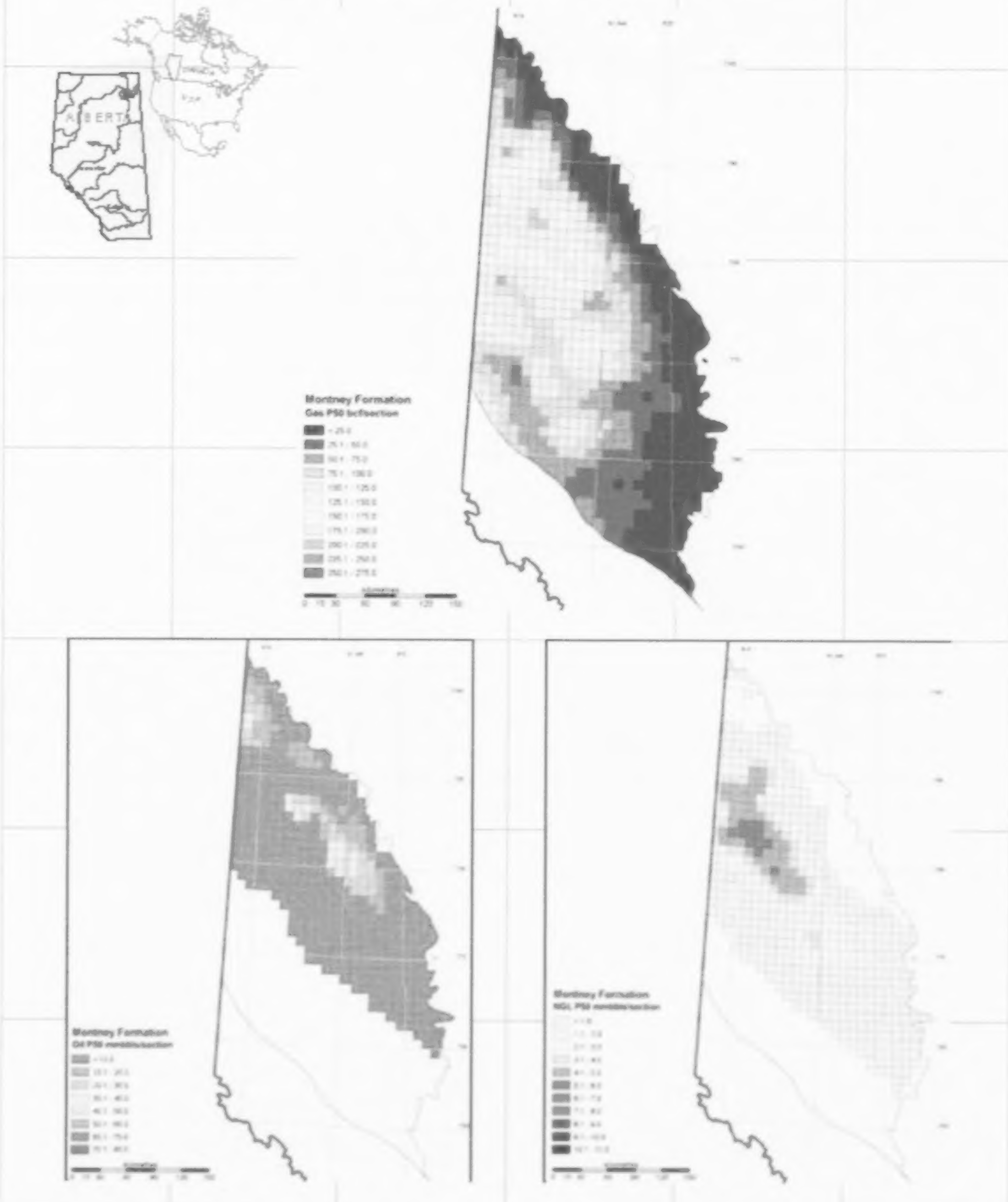


Figure AF.4

P50 gas, oil, and liquids initial in-place for the Banff/Exshaw Formation

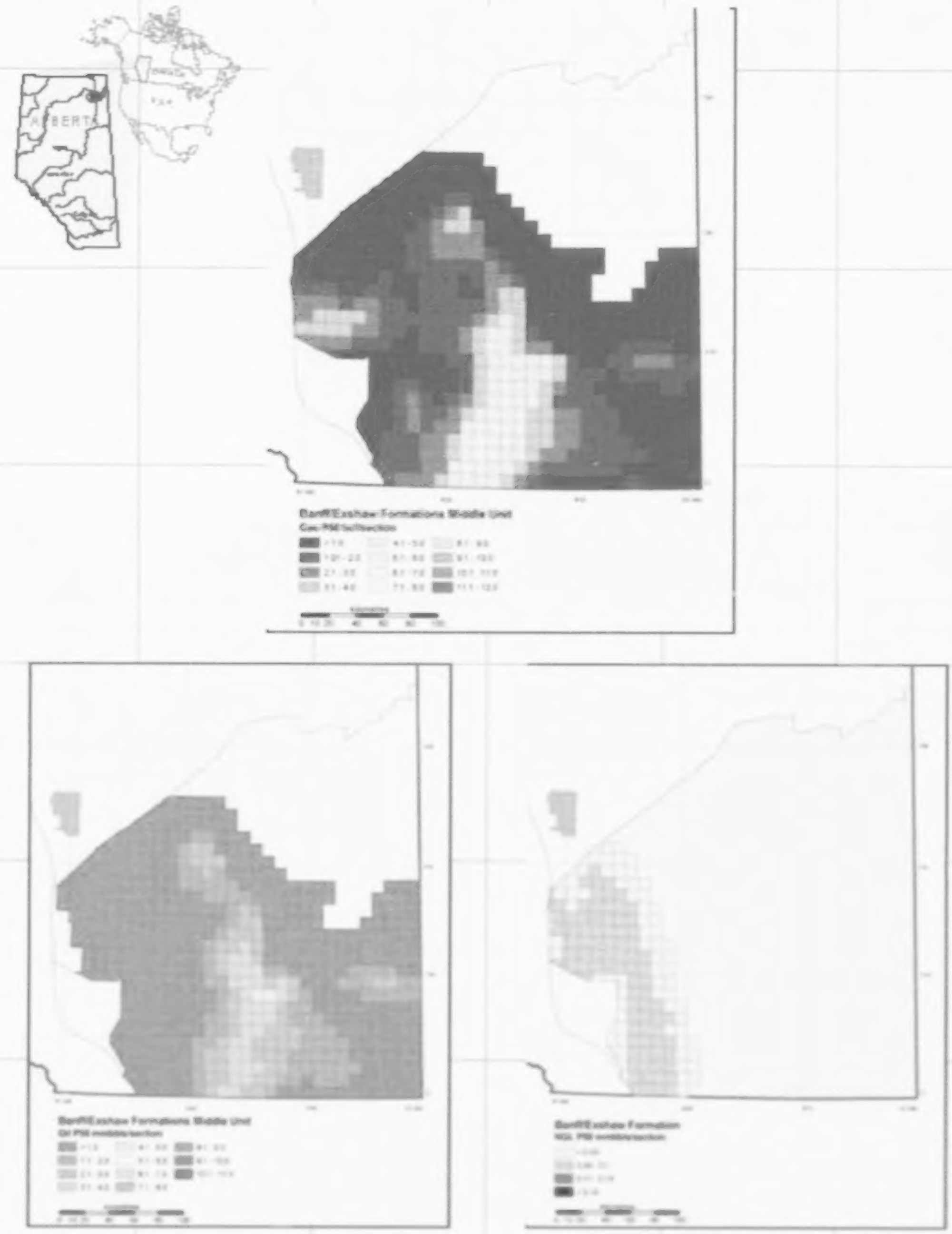


Figure AF.5

P50 gas, oil, and liquids initial in-place for the Nordegg Formation

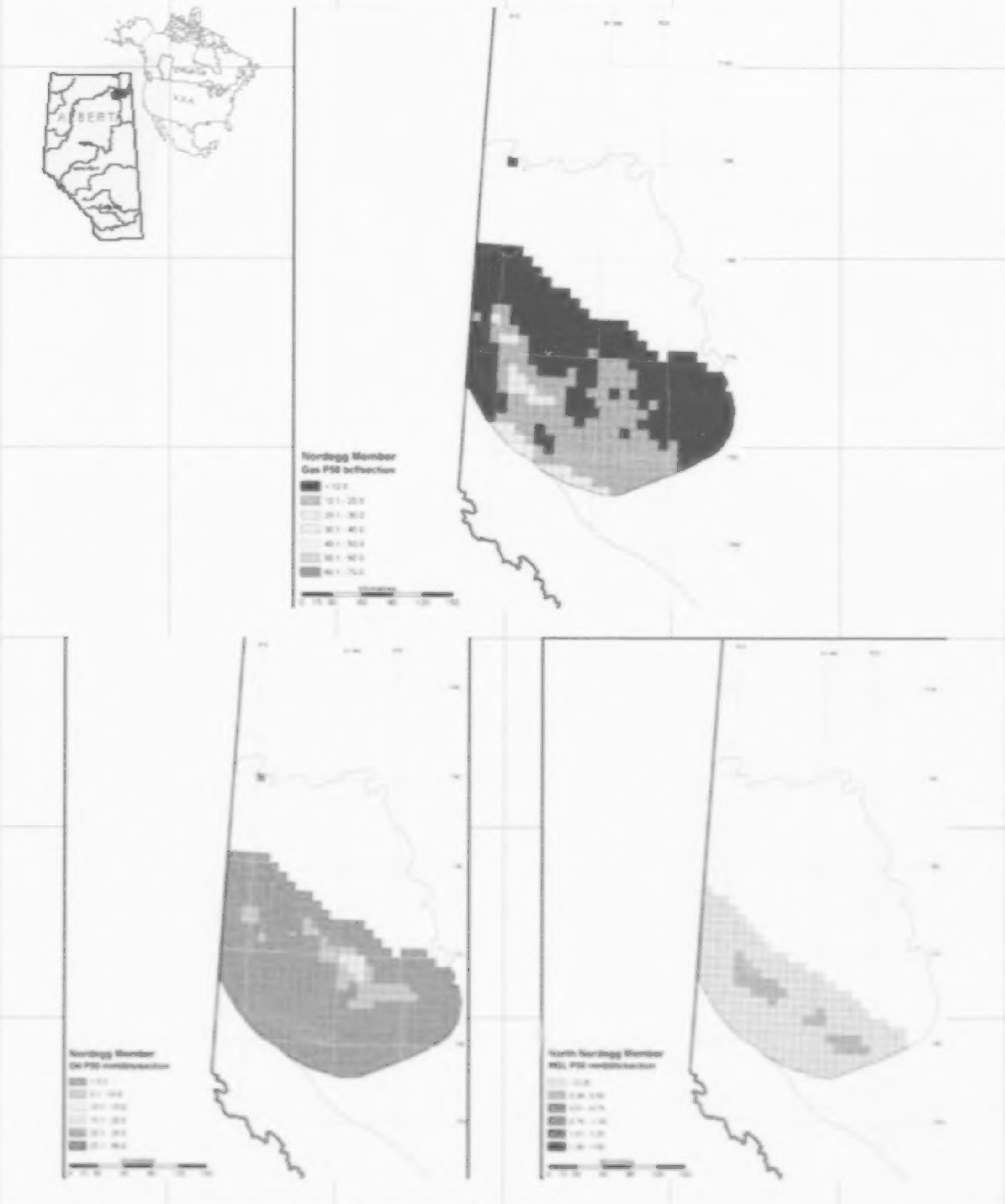
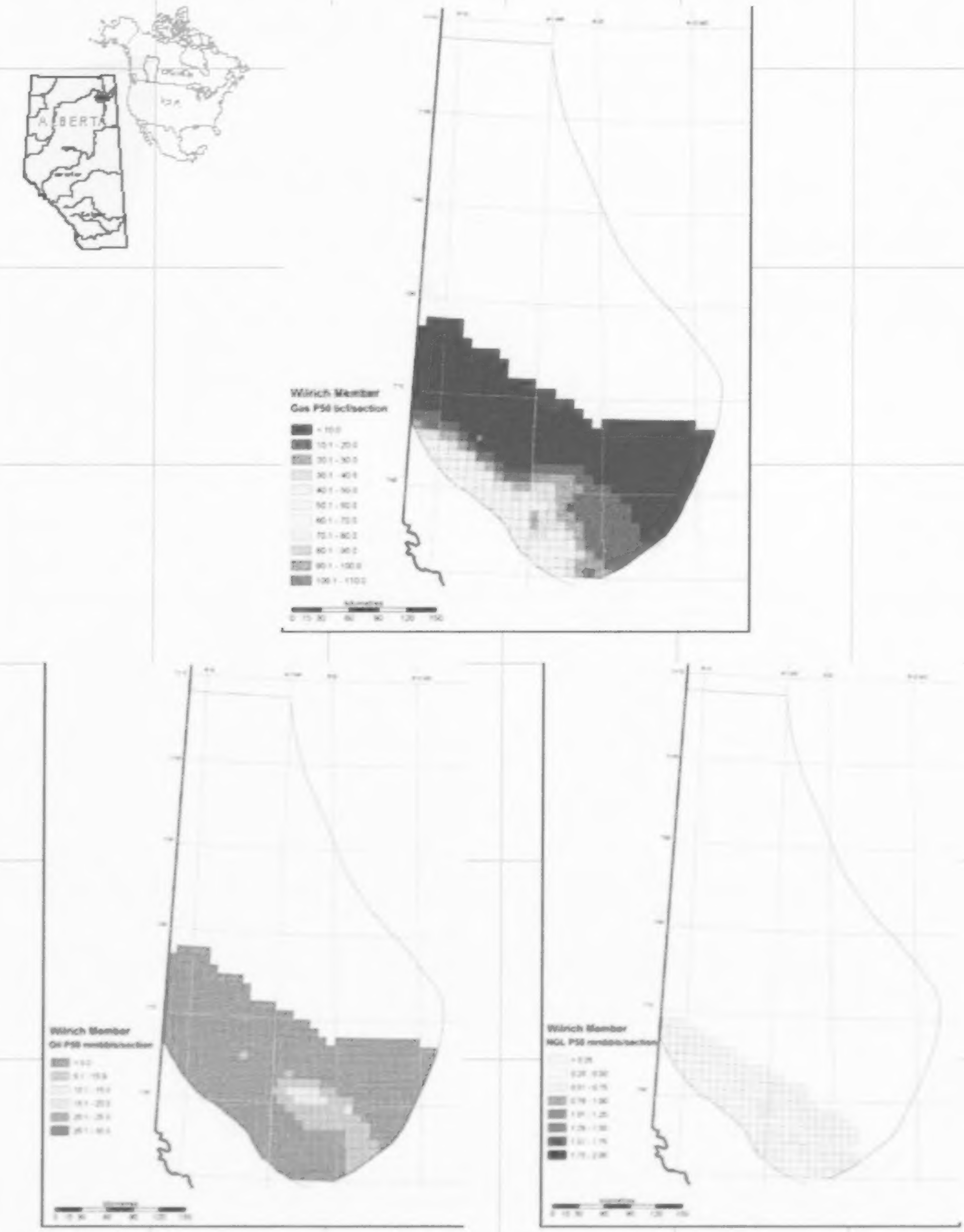


Figure AF.6

P50 gas, oil, and liquids initial in-place for the Wilrich Formation



NATURAL GAS

Alberta's remaining established conventional natural gas reserves decreased by 2% in 2013 to 896 billion cubic metres

Marketable gas production declined by 3% (6% in 2012)

ECONOMICS

Natural Gas Prices averaged $2.83 in 2013 ($2.14 in 2012)

Oil Prices averaged $98.05 in 2013 ($94.15 in 2012)

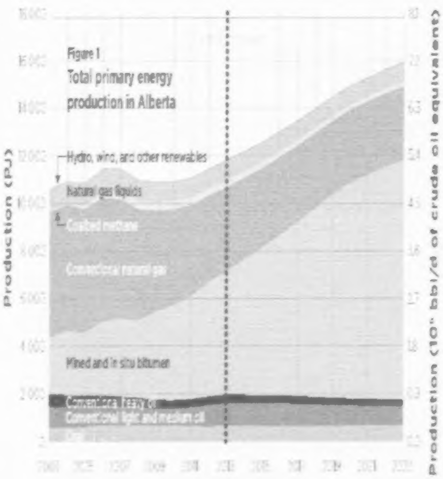
Alberta Energy Regulator

NGLs

Reserves: Ethane ↑ 2%, Propane ↑ 3%, Butane ↑ 2%, Pentane Plus ↓ 1% respectively in 2013

Production: Ethane ↑ 6%, Propane ↑ 4%, Butane ↑ 5%, Pentane Plus ↑ 9% respectively in 2013

FORECASTING



CRUDE OIL

Remaining established reserves increased by over 5% in 2013 to 283 billion cubic metres

Production increased by 5% in 2013 compared with 2012

Deliveries of Gas

Deliveries of Crude Oil

CRUDE BITUMEN

OVER 200 YEARS of supply at current production levels

Mineable production 5% + In situ production increased by 12% = Total bitumen production 8%

RESOURCE ENDOWMENT

The geological framework of the Western Canada Sedimentary Basin.

The AER regulates some of the world's largest hydrocarbon resources.

COAL

OVER 1000 YEARS of supply at current production levels

Production increased by 3%

HIGHLIGHTS

Alberta's Energy Reserves 2013 and Supply/Demand Outlook 2014–2023

ST98

2014